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To my beloved mother and father

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Abstract

Deepwater is defined as water depths that are greater than 1 000 ft. The exploration and development activities in deepwater are the Oil and Gas industry's biggest challenges, and they demand a huge investment. However, the high reserve potentials provide greater rewards. The purpose of this thesis is to review well's Life Cycle challenges, and some field proved technology solutions to mitigate and control the problems.

The first section presents a literature study based on the operational problem and solutions during *exploration, drilling, completion/production and plugging & abandonment phases*. The major investigations of the overall studies are briefly summarized in chapter 6. For instance, based on the field case studies, *Managed Pressure Drilling (MPD)* and *Flat Rheology (FR)* are reliable technologies when operating in a narrow window and High Pressure High Temperature (HPHT) formation.

The second section presents simulation and analysis focusing on sensitivity studies of *the annular pressure build up (APB) and its effect, kick tolerance (KT), well cementing, high pressure, and high-temperature effects on drilling fluid*. Among the simulations studies, the *managed pressure cementing (MPC)* was found out to be a successful method when cementing in a narrow operational window.

The solutions for deepwater challenges are already available on the market. However, there is still a need for further technological development and new methods to improve the operation and cost effectively.

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List of symbols

A_i	Area on the inside of the pipe, in^2
A_o	Area on the outside of the pipe, in^2
B_N	Fluid compressibility, psi^{-1}
β	Buoyancy factor
$\beta(T)$	Viscous coefficient linearized with Temperature
β_0, β_1	Viscous parameters, $1/_{bar}$ ℃
c	Compressibility of fluid, 1/ psi
C_1, C_2	Empirical constant, ℃
d	Diameter, m
E	Young is modulus, psi
f	Friction factor
F_{bal}	Ballooning effect force, ibf
h_{tvdcs}	Depth difference through vertical depth at current shoe, ft
K	Surface roughness
L	Length, m
ΔL	Length change, in
n_o	Plastic viscosity of fluid, $Pa.s$
P_b	Burst Pressure, psi
P_c	Collapse Pressure, psi
P_e	External pressure, psi
P_i	Internal or inner pressure, psi
P_{Pore}	Pore pressure, psi
$P_{bottomhole}$	Bottom hole pressure, psi
$P_{hydorostatic}$	Hydrostatic Pressure, psi
$P_{friction}$	Friction pressure, psi

P_{choke}	Choke Pressure, psi
ΔP	Change in pressure, psi
ΔP_{ads}	Change in Drill string and riser, psi
P_0	External Pressure, psi
P_{CS}	Pressure at casing shoe, psi
R_e	Reynolds number, [-]
r_i	Inner radius, in
r_0	Outer radius, in
u	Flow velocity, m/s
V	Expanded volume, in^3
V_o	Initial volume, in^3
Δs	Length of casing, in
T_3, T_4	Circulation of Top and Bottom Temperatures, ℃
T	Temperature, ℃ or °F
ΔT	Change in Temperature
α	Thermal expansion, $1/$°F
γ	Shear rates, $1/S$
ρ	Static fluid density, kg/m^3, ppg
ρ_{mix}	Active mud density with influx, kg/m^3 , ppg
ρ_{mud}	Active mud density, $kg/m^3, ppg$
ρ_f	Density of fluid, kg/m^3, ppg
ρ_s	Density of steel, kg/m^3, ppg
ρ_o	Atmospheric pressure, psi
μ	Viscosity, cP
τ	Bingham shear stress, Pa

List of abbreviation

APB	Annular Pressure Buildup
API	American Petroleum Institute
BHP	Bottom Hole Pressure
BOP	Blow Out Preventer
BSR	Bottom Simulating Reflector
CBL	Cement Bond Log
DGD	Duel Gradient Drilling
ECD	Equivalent Circulating Density
FPU	Floating Production Units
FPSO	Floating Production Storage Offloading
HSE	Health, Safety and Environment
HPHT	High Pressure, High Temperature
IPF	Insulating Packer Fluid
IADC	International Association of Drilling Connectors
KT	Kick Tolerance
LMRP	Lower Marine Riser Package
MD	Measured Depth,[ft.]
MPD	Managed Pressure Drilling
MPC	Managed Pressure Cementing
MFC	Micro Flux Control
MMS	Mineral Managed Service
MMcf	Million Standard cubic feet per day
MODU	Mobile Offshore Drilling Units
NPT	Non -Productive Time
NCS	Norwegian Continental Shelf
PDC	Polycrystalline Diamond Compact
P&A	Plug and Abandonment
PWC	Perforate Cement Wash
PV	Plastic Viscosity, cP
RD	Riser Less Drilling
RCD	Rotating Control Device
RTM	Reverse Time Migration
RLWI	Riser Less Light Well Intervention

SW	Seawater
SG	Specific Gravity
SAA	Steel Alloy Aluminum
SCR	Steel Catenary Riser
SPAR	Single Point Anchor Rig
TD	Target Depth
TTI	Tilted Transverse Isotropy
TLP	Tension Leg Platform
TVD	True Vertical Depth
TTBP	Total Time Per Well
USIT	Ultra Sonic Imager Tool
VIT	Vacuum Insulating Tubing
VIV	Vortex Induced Vibration
VDL	Variable Deck Load, mT
WAT	Wax Appearance Temperature
WLF	William Landed Ferry
WEM	One-Way Wave Migration
YP	Yield Point, Pa
Al	Aluminum
CO_2	Carbon dioxide
Ca (CL_2)	Calcium chloride
H_2S	Hydrogen sulfide
HCOOK	Potassium formate
Me (OH)	Methanol
Na (CL_2)	Natrium Chloride
O_2	Oxygen
Ti	Titanium

1. Introduction

Deepwater development is growing fast in today's Oil and Gas industry. The Deepwater area has both challenges and opportunities. The challenges raise the operational cost and technical risks significantly. Offshore petroleum operation environment is categorized based on the depth of water. Namely, shallow water, (0-1 000ft), deepwater (1 000-5 000ft) and Ultra-deepwater (>5 000ft) [1]. Gulf of Mexico, Brazil and West Africa are among the most attractive regions for deepwater operations with a steady increase for subsea well drilling technology. As depicted in figure 1.1, almost 30% of oil and gas fields are located in the western Africa region, Gulf of Mexico, and in Brazil which has an average depth of 4004 ft. [2].

Figure 1.1 Deepwater area in the world. [2]

During the lifetime of a well, it is therefore important to:

- Maximize production and return on investment.
- Reduce non-productive time.
- Increase operational and material efficiency.
- Decrease operational uncertainties.
- Reduce challenges with respect to *Health, Safety and Environment (HSE)* issues.

This thesis will focus on the challenges associated with the four phases of operation, which are *exploration, drilling, completion/production,* and *P&A*. Based on field case studies, a proven and conceptual technological and engineering solution will be presented.

1.1 Research Motivation and problem formulation

Figure 1.2 displays an illustration of deepwater drilling challenges starting from the surface and going all the way down to the reservoir section. High reserve levels of these regions are making them attractive investment regions for oil and gas industry, especially for High Pressure - High Temperature (HPHT) wells, as well as reservoir wells located in pre and post salt formation. Continuous technological advances have made the investors in this harsh region the biggest beneficiaries. It has become possible to extract oil in even extremely deepwaters with little or no light visibility and sub-zero Temperature, not to mention other challenges such as pressure, hydrates, wax build-up, etc.

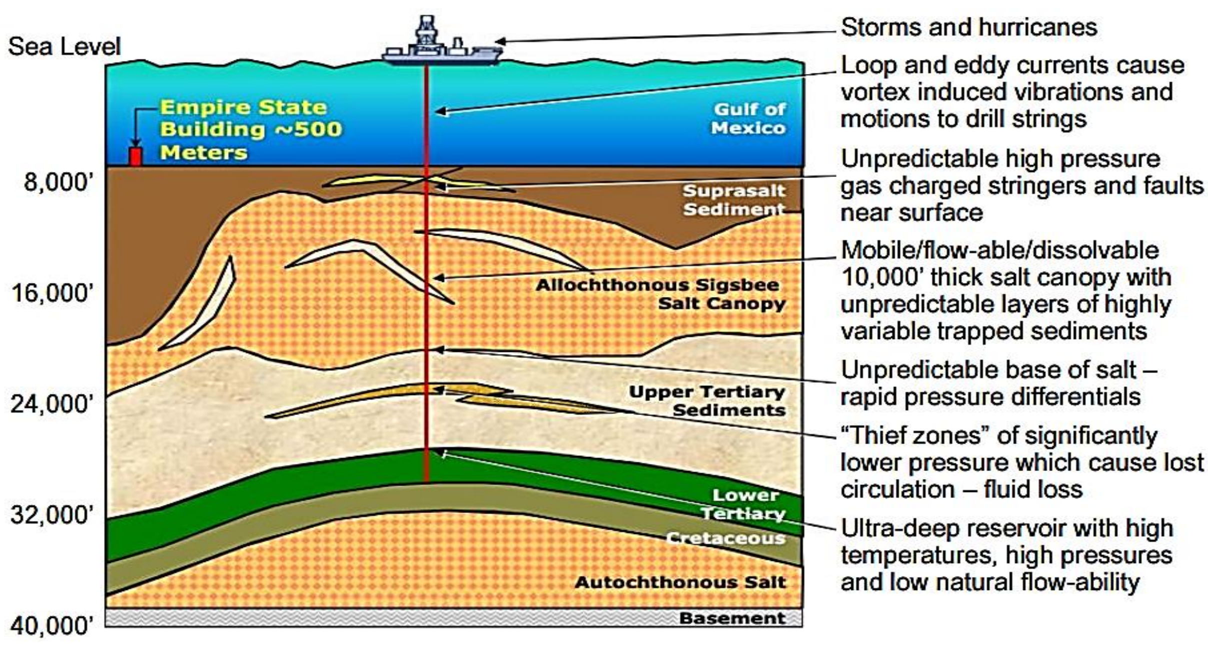


Figure 1.2 GOM Ultra-deepwater drilling technical challenges. [1]

Platforms rate can exceed 500 000 USD/day which is expensive [3]. In addition, rig positioning, riser management, well cementing, and well control are also challenging issues. The deeper the operation goes, the more apparent the challenges become, which is mostly due to limitations regarding facilities, cost, operational technology, and weather factors.

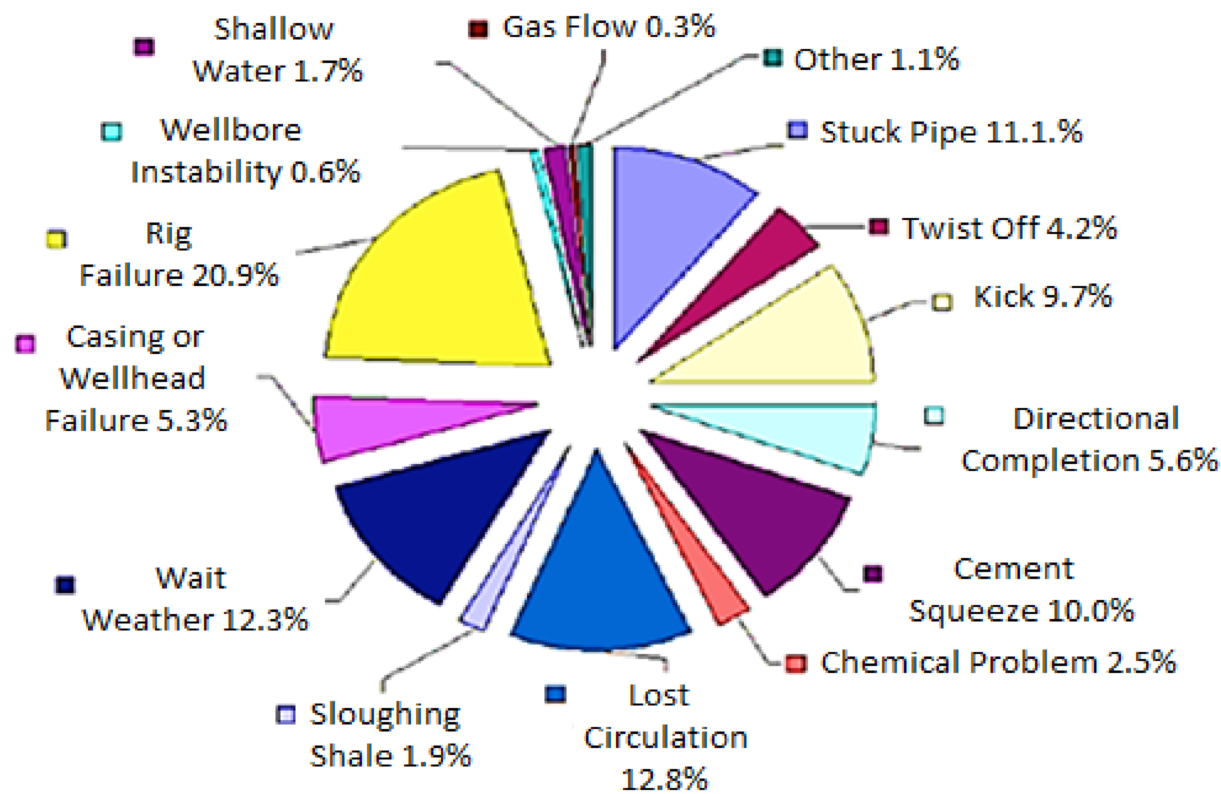


Figure 1.3 Drilling down time in deepwater field > 15 000 ft. [4]

Figure 1.3 shows the *NPT (Non-Productive Time)* in deepwater with respect to activities. Some of the central challenges may occur at the location of the well, where the well will be exposed to HPHT condition with a small margin between pore pressure and fracture pressure. This leads to loss of circulation, collapse, kick, and fracture. The pressure related problems would increase to about 40% of NPT. The economic impact of NPT is estimated to be around 98 USD/ft. for deepwater exceeding 15 000 ft. depth [4].

To evaluate and describe the life cycle of deepwater challenges briefly, this thesis addresses issues such as:

- What are the challenges associated with the different operational phases during the life cycle of the well?
- What are the current technology solutions to handle, analyse and solve the challenges?
- What is the effect of Temperature on the drilling fluid and its consequences in the operational phase?
- How to manage drilling and well construction processes in deepwater operations?

1.2 Objective

The primary objective of this thesis is:

- To present field case study on deepwater petroleum operations challenges and solution during the lifetime of a well.
- To perform a simulation study.

1.3 Research Methodology

The structure of the thesis is summarized in Figure 1.4. The research method is divided into two main topics, literature study and simulation design analysis.

The literature study deals with the review of challenges in deep and Ultra-deepwater of the oil and gas field. That includes activities during Exploration, Drilling, Completion/Production and Plugging and Abandonment phases. Some of the solutions for the associated challenges are evaluated based on field case studies.

The simulation studies part includes kick tolerance, management pressure cementing and HPHT effect on drilling fluid. Numerical examples are also presented, which illustrates the effect of annular pressure buildup that leads to a ballooning effect on casing and production tubing.

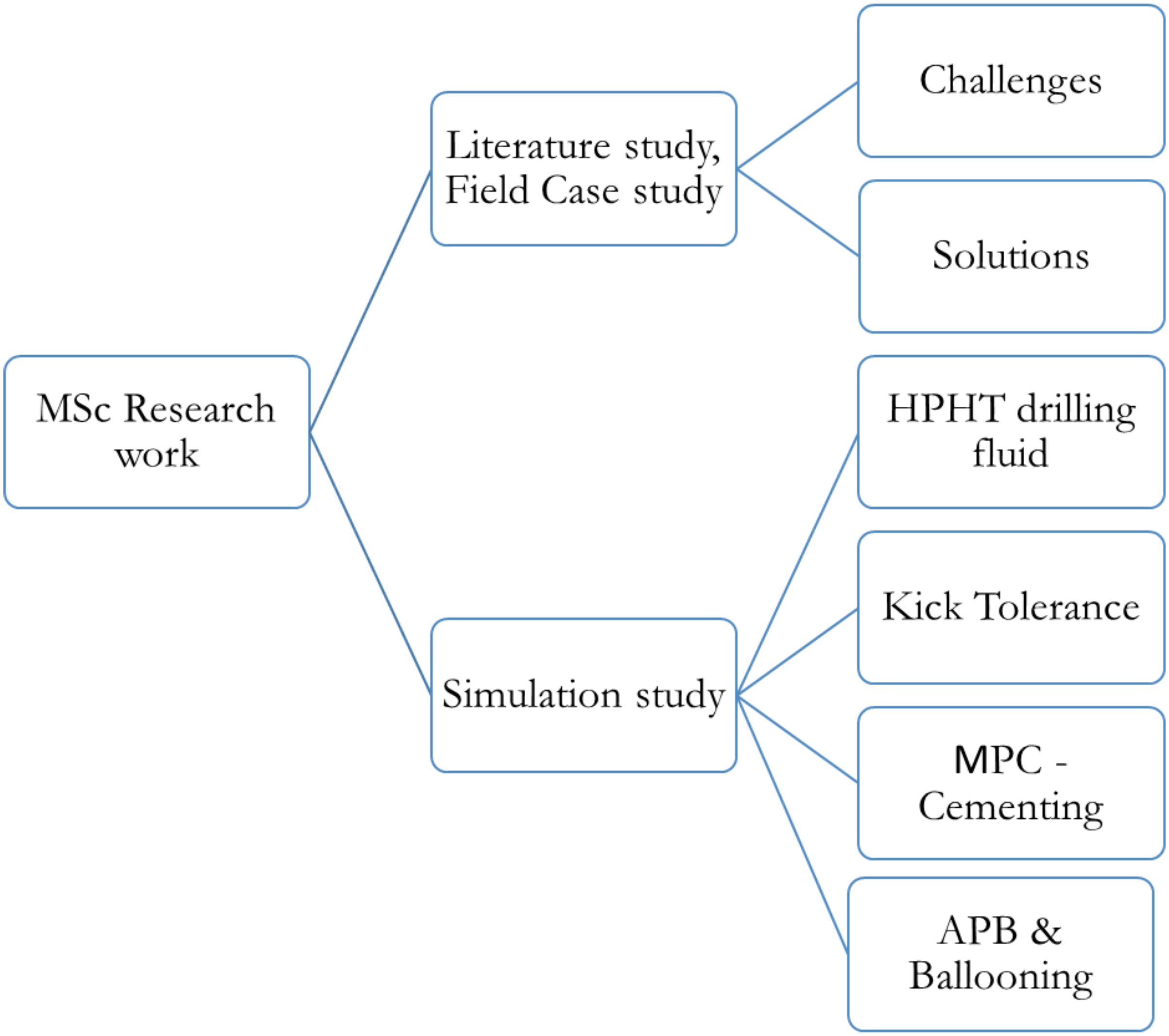


Figure 1.4 Thesis structure.

2. Literature Study

This chapter presents a description of the deepwater environment plus the theories used for simulation design analysis that is simulated in chapter 4.

2.1 Environmental Condition

Environmental issues arise due to several different reasons, to propose the best and most efficient solution, it is necessary to be familiar with the sub-oceanic conditions. It is therefore important to get an overview of the process that influences these activities, especially current, Temperature, salinity, and pressure.

2.1.1 Currents

Currents are masses of water body moving in a particular direction in the sea. They are driven by thermal and salinity variation of the water at different locations. The deeper sections of the ocean have lower speed and lower Temperature with high density and no exposure to oceanic wind.

Due to a higher Temperature, the surface is characterized by lower density and higher speed [5]. The difference in speed at the upper and lower region of the ocean generates a circulation motion as illustrated in figure 2.1. The current motion will apply load on the riser and hence have effect on drilling vessels [6].

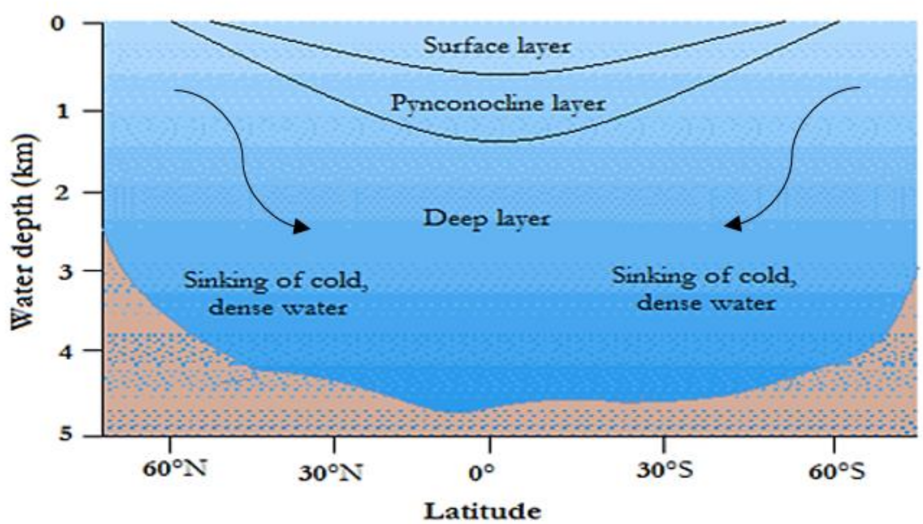


Figure 2.1 Density structure of the ocean. [5]

2.1.2 Temperature

Temperature has a major influence on the physical and chemical processes such as for the formation of hydrate and wax in flow lines. The Temperature in the ocean and at the seabed is very low, which averages around 40 ^{0}F at the mudline. Figure 2.2 shows a typical Temperature profile for deepwater areas such as in Gulf of Mexico (GOM) and West Africa [6].

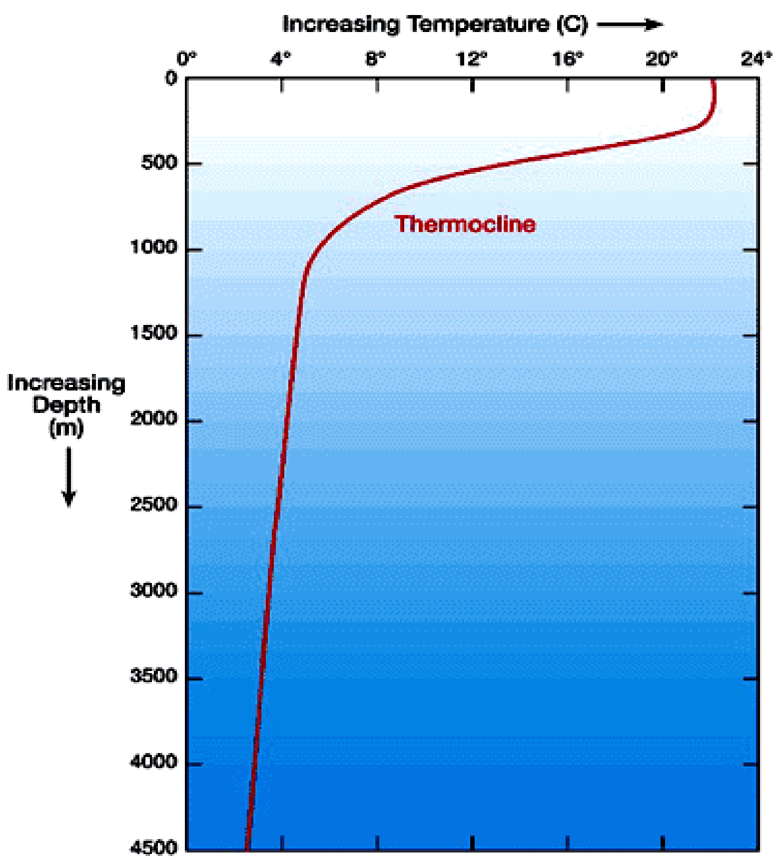


Figure 2.2 Temperature profile in deepwater. [6]

In addition to Temperature, salinity and pressure are also critical issues to be considered. Temperature and pressure determine the thermodynamic states flow assurance problems. The low Temperature and high pressure are favourable conditions for hydrate formation in the flow lines at the seabed. During operation, it is important to regularly simulate and carry out flow assurance measures to mitigate flow restrictions [6].

2.1.3 Salinity

Deepwater drilling operations are typically conducted within a salt-water environment. Seawater usually contains about 3.5% salt, and the density of seawater is a function of the salinity. The higher salinity is, the denser the water becomes [5]. The evaporation and the precipitation process of the salt water control the salinity of the water. At the mud-line region, the Temperature is usually just a few degrees above $0℃$ but some deepwaters can have a Temperature that is below $0℃$ and it still does not freeze because of the presence of salinity and high pressure [6].

2.2 Theory

This section describes the theories used for the simulation study part in chapter 4.

2.2.1 Rheology

To predict the fluid flow desired parameters, it is important to characterise the fluid and deformation properties. That is known as Rheology. Fluid flows due to the applied shear stress that causes shear deformation. The rheological parameters that are used to predict for instance the hole cleaning and hydraulics performance of drilling fluid can be determined depending on the fluid behaviour. Generally, rgeological fluid parameters is a function of Plastic Viscosity (PV), Yield Point (YP) and Gel Strength (GEL). The Bingham's plastic model is a function of PV and YP. In order to set fluid in motion, the applied shear stress should overcome the yield stress. The Bingham's shear stress (τ) and shear rates (γ) calculate model is: [7]:

$$\tau = YS + PV\gamma \tag{1}$$

Where;

YS = Shear yield stress, $\left[\frac{Ibf}{100sq\ ft}\right]$

PV = Plastic viscosity, $[cp]$

2.2.2 Equivalent Circulating Density (ECD)

As the fluid flows into a well, the effective fluid density that is applied on the wellbore is known as *Equivalent Circulation Density (ECD).* That is a function of the static mud density, and the dynamic annular pressure loss of fluid that flows through a distance. During the drilling operation, the well's stability is managed by designing the right ECD making sure that it is between the allowable operational windows. Poorly designed drilling fluid and wrong predicted ECD will result in undesired drilling related problems such as kick, fluid loss circulation, and well collapse.

The overall results increase the operational cost immensely. The main controlling parameters of ECD are drilling fluid rheology, density, fluid injection rate, and the geometry of the fluid transport media. ECD management would be a difficult task when drilling in deepwater environment where the window between pore pressure and fracture gradient (FG) is narrow. ECD calculated from the hydrostatic and frictional pressure as [8]:

$$ECD = \rho + \frac{\Delta P_d}{0{,}052 \times TVD} \tag{2}$$

Where;

ECD	=	Equivalent circulating density, [ppg]
ρ	=	Static fluid density, [ppg]
ΔP_d	=	Annulus frictional pressure loss at a given circulation rate, [psi]
TVD	=	True vertical depth of the well, [ft.]

2.2.3 Hydraulics

Figure 2.3 illustrates the fluid flows through surface equipment, pipe, nozzle and annulus of drilling well. The pump pressure should overcome all pressure losses occurring in the fluid lines since fluid flows due to friction and energy loss.

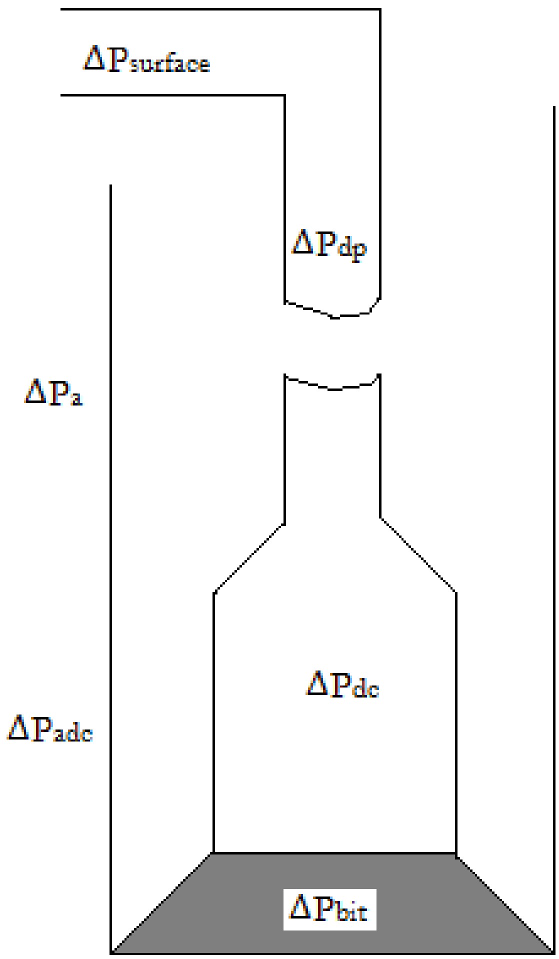


Figure 2.3 Fluid circulating in a drilling well.

Normally available pump surface pressure given as standpipe pressure determined by the sum of all the pressure losses ca be calculated with the following formula [7]:

$$\Delta P_{s,opt} = \Delta P_{fs} + \Delta P_{fdp} + \Delta P_{fdc} + \Delta P f_{fadp} + \Delta P f_{fadc} + \Delta P_{fb} \quad (3)$$

Where;

ΔP_{fs}	=	Friction Pressure loss in Surface connection, [psi]
ΔP_{fdp}	=	Friction Pressure loss in drill pipe, [psi]
ΔP_{fdc}	=	Friction Pressure loss in drill collar, [psi]
ΔP_{fadp}	=	Friction Pressure loss in Annulus around drill pipe, [psi]
ΔP_{fadc}	=	Friction Pressure loss in annulus and drill collar, [psi]
ΔP_{fb}	=	Friction pressure loss at drill bit, [psi]

The equations below show the pressure loss in the annulus for fluid flow, where the pressure decrease due to friction [7]:

$$\Delta P = \frac{2fL\rho u_m^2}{D} \tag{4}$$

$$f = \frac{16}{R_e(p,v)} \tag{5}$$

Where;

R_e	=	Reynolds number
f	=	Friction factor
L	=	Length of annulus, [m]
ρ	=	Mud density, $[\mathrm{kg}/\mathrm{m}^3]$
u	=	Flow velocity, [m/s]
D	=	diameter, [m]
v	=	Viscosity, [cp]

Haaland's formula for tubular flow gives an approximate value for surface roughness as shown below [9].

$$\frac{1}{\sqrt{f_F}} = -3,6\, log_{10}\left\{\frac{6,9}{R_e} + (\frac{\varepsilon}{3,71})^{111}\right\} \tag{6}$$

$$\varepsilon = K/d \tag{7}$$

For torque and drag, the drilling fluid density influences the buoyancy factor. The formula can be determined as [9]:

$$\beta = 1 - \frac{\rho_{f\,(T,P)}}{\rho_s} \tag{8}$$

Where;

K	=	Surface roughness
D	=	Diameter of drill pipe$[in]$
β	=	Buoyancy factor
ρ_f	=	Density of fluid $\left[{kg}/{m^3}\right]$
ρ_s	=	Density of steel $\left[{kg}/{m^3}\right]$

2.2.4 Temperature of Drilling Fluid in Pipe and Annulus

Figure 2.4 illustrates the cold drilling fluid injection through the pipe and the warmer drilling fluid as it returns through the annulus. Kaarstad and Aadnøy have modelled the Temperature profiles of the drilling fluid in pipe and annulus given by equations (9) and (10) respectively [10].

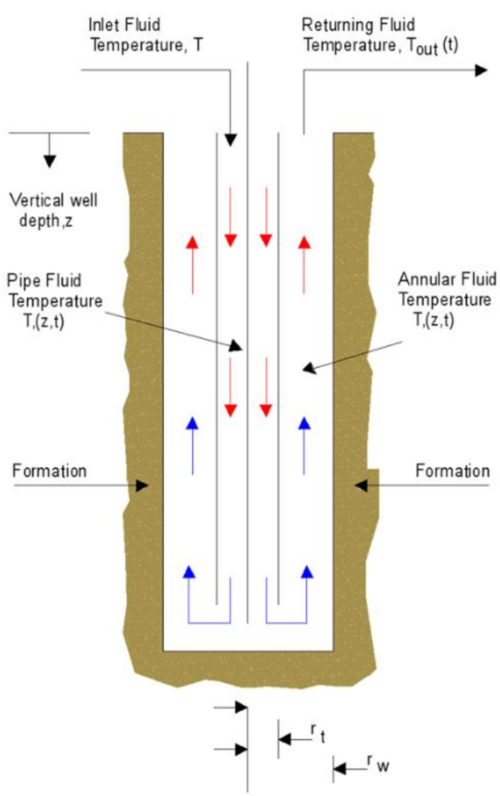


Figure 2.4 Illustration of fluid flows through drill pipe and return through annulus. [10]

Temperature in drill string:

$$T_d(z,t) = \alpha e^{\lambda_1 z} + \beta e^{\lambda_2 z} + g_G z - Bg_G + T_{sf} \tag{9}$$

Temperature in annulus:

$$T_a(z,t) = (1+\lambda_1 B)\alpha e^{\lambda_1 z} + (1+\lambda_2 B)\beta e^{\lambda_2 z} + g_G z - Bg_G + T_{sf} \tag{10}$$

Where A, B, λ_1, λ_2, α and β can be calculated:

$$A = \frac{w C_{fl}}{2\pi r_c U_a}\left(1 + \frac{r_c U_a f(t_D)}{K_f}\right) \tag{11}$$

$$B = \frac{w C_{fl}}{2\pi r_c U_a} \tag{12}$$

$$\lambda_1 = \frac{1}{2A}\left(1 - \sqrt{1 + \frac{4A}{B}}\right) \tag{13}$$

$$\lambda_2 = \frac{1}{2A}\left(1 + \sqrt{1 + \frac{4A}{B}}\right) \tag{14}$$

$$\alpha = -\frac{(T_{in} + B_{gG} - T_{sf})\lambda_2 e^{\lambda_2 D} + gG}{\lambda_1 e^{\lambda_1 D} - \lambda_2 e^{\lambda_2 D}} \tag{15}$$

$$\beta = -\frac{(T_{in} + B_{gG} - T_{sf})\lambda_1 e^{\lambda_1 D} + gG}{\lambda_1 e^{\lambda_1 D} - \lambda_2 e^{\lambda_2 D}} \tag{16}$$

2.2.5 Temperature and Pressure Dependent Viscosity

As fluid flows into a wellbore, the Temperature and pressure increase. These thermodynamic states influence the viscosity and density of the drilling fluid. There are several empirical models, which describe Temperature and pressure effect. For analysis purpose in this thesis, the factorial *WLF–Barus* (William Landel Ferry) have been used and calculated by [11]:

$$n(p,T) = n_o 10^{\left(\frac{C_{1(T-T_0)}}{C_{2+(T-T_0)}}\right)} \exp\left(\beta\,(T)\,(P - P_0)\right) \tag{17}$$

And

$$\beta(T) = (\beta_0 + \beta_1)\ (T\text{-}T_0) \tag{18}$$

Where:

n_o = Plastic viscosity of fluid, [Pa. s]

P_0 = Pressure of reference, [psi]

T_0 = Temperature of reference, [℃]

C_1, C_2 = Experimental constant, [℃]

$\beta(T)$ = Piezo Viscous coefficient linearized with Temperature

β_0, β_1 = Viscous parameters, [$^1/_{bar}$ ℃]

The correlation parameters used in WLF–Barus model for oil base and drilling fluid studies are shown in the Table 2.1:

Table 2.1 Model parameters. [11]

Sample	n_o	C_1	C_2	β_0	β_1
Sr – 10 oil	0.114	2.54	80.65	2.62×10^{-3}	-1.43×10^{-5}

2.2.6 Thermal Induced Tubular Change in Tubing

Thermal expansion or contraction causes a change in the length of the tubing, since metal expands when it heats up and contracts when it cools down. For tubing which experience, Temperature changes through its entire length, the elongation or contraction can be of a considerable amount [6].

The change for tubing length due to heat is calculated by formula:

$$\Delta L = C_T\ L\ \Delta T \tag{19}$$

Where: C_T is the of thermal expansion [1/°F], L is the length of tubing [ft.], and ΔT is change in temperature [°F].

2.2.7 Thermal Induced Loading

Tubing and casing are subjected to Temperature and will therefore expand when Temperature increase. Since the casing is fixed on the surface of the wellhead (top end) and at the depth by the hardened cement (bottom end), heating will cause a compressive force, and cooling will cause a tensile force. Thermally induced loading is mathematically calculated by applying the following formula [6]:

$$\mathrm{F_{temp}} = -EC_T \Delta T \Delta A \tag{20}$$

Where;

$\mathrm{F_{temp}}$	=	Tensile force, $[Ib]$
E	=	Young's modulus, $[psi]$
ΔA	=	Cross sectional area of tubular, $[inch^2]$

The coefficient of Thermal expansion is a material property therefore C_T will vary with different metallurgies.

2.2.8 Annular Pressure Build-Up (APB)

To maintain the mechanical integrity, it is important to seal the annular spacing that controls the changes in the fluid pressure and Temperature. The fluid that is trapped within the annular well heat up. In a sealed annulus, the change in volume results in a substantially increased pressure. The *Annular Pressures Buildup (APB)* phenomenon, commonly observed in all producing wells because of the Temperature differences between the cold seabed Temperature and the fluid production Temperature. That means the volume expansion is proportional to the change in Temperature, the original volume, and the fluid thermal expansion [12]. Mathematically, the final volume can be calculated as [13]:

$$V = V_o(1 + \alpha \Delta T) \tag{13}$$

If the fluid is constrained, the change in pressure due to the increase in volume is given as:

$$\Delta P = \frac{V - V_o}{V_o B_N} \tag{22}$$

By inserting Eq. 21 into Eq. 22, the build-up pressure regarding the fluid properties and average change of Temperature is mathematically calculated as:

$$\Delta P = \frac{\alpha \Delta T}{B_N} \tag{23}$$

Where:

V	=	Expanded volume, $[in^3]$
V_o	=	Initial volume, $[in^3]$
α	=	Fluid thermal expansively, $[°F^{-1}]$
ΔT	=	Average change fluid change in Temperature, [°F]
ΔP	=	Average change fluid change in Temperature, $[psi]$
B_N	=	Fluid compressibility, $[psi^{-1}]$

2.2.9 Ballooning

The ballooning phenomena are based on the variations in the average pressure inside and outside the tubing string. When the tube is loaded in axial tension, axial strain and radial compressive strain is generated, and they are proportional to one another in the elastic region. During stimulation, or gas life operation, the tubing may experience ballooning and reverse ballooning. That results in string compression and elongations respectively. The change in pressure is relative to the pressure on the completion at the time of the initial condition. For free moving tubing, applied internal pressure will allow the tubing to shrink and applied external pressure will allow elongation. The change in length due to ballooning effect is calculated by applying the following formula [6]:

$$\Delta L_{bal} = -2\mu \frac{(\Delta p_i A_i - \Delta p_o A_o)}{(A_o - A_i)} \frac{L}{E} \tag{24}$$

Force caused by Ballooning is expressed as follows:

$$F_{bal} = 2\mu \, (A_i \Delta p_i - A_o \Delta p_o) \tag{25}$$

Where;

$\Delta L_{bal} =$ Length change due to ballooning, $[ft.]$

F_{bal} = Ballooning effect force, $[ibf]$

μ = Poisson´s ratio, 0.3 for oil field steel

Δp_i = Change in internal pressure, $[psi]$

Δp_o = Change in external pressure, $[psi]$

A_i = inside of the pipe, $[in^2]$

A_o = Outside area of the tubing, $[in^2]$

L = Length of tubing $[ft.]$

2.2.10 Tubular Loads on Casing

The casing exposed to extreme loads during the life cycle of deepwater operations. These loads can be categorized into two subgroups of loadings, one of these groups is Burst and Collapse load *(Radial load),* and the other is Tensile and Compressive load (*Axial load)* [8].

2.2.10.1 Radial Loads on Casing

1. ***Burst Load:***

For Burst Load, the casings will undergo a final burst loading if the internal radial load exceeds the external radial load. This situation could take place when the pressure in the tubing increases during simulation and bull heading the operation. For a safe tubular condition, the burst load at any given point along the casing/tubing is calculated by applying the formula:

$$P_b = P_i - P_e \tag{26}$$

2. ***Collapse Load:***

For Collapse Load, the casing will undergo a final collapse loading if the external radial load exceeds the internal radial load as shown in figure 2.5. This situation could take place during APB and gas lift operations. For a safe operation, the burst load at any given point along the casing/tubing is calculated by applying the formula:

$$P_c = P_e - P_i \tag{27}$$

Where:

P_b = Burst Pressure, $[psi]$

P_c = Collapse Pressure, $[psi]$

P_e = External Pressure, $[psi]$

P_i = Internal Pressure, $[psi]$

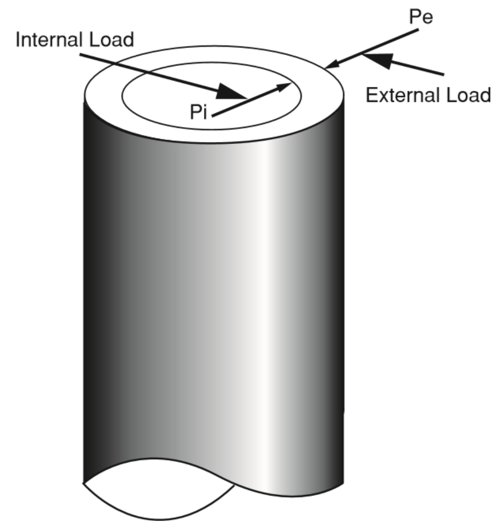


Figure 2.5 Radial load on casing. [8]

2.2.10.2 Axial Loads on Casing

During installation, drilling, and production, the casing experiences a broad range of axial loads. Depending on the operating conditions, the axial load on the casing is either compressive load or tensile load. These axial forces will vary along the length, which is shown in figure 2.6.

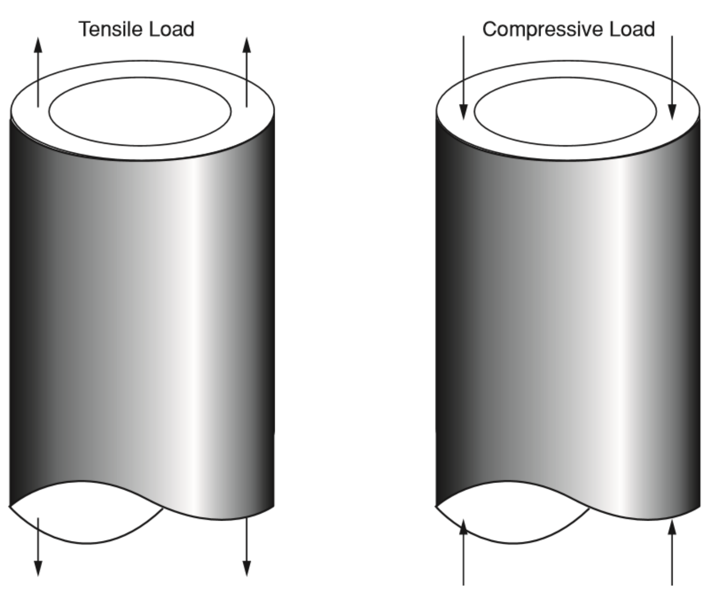


Figure 2.6 Axial load on casing. [8]

Axial loads on the casing are a function of different variables such as the dry weight of the casing, buoyant force on the casing, bending stress, plug bumping pressure, over-pull when the casing is stuck, Temperature changes, and ballooning during pressure testing.

3. Case Study: Well's Lifetime – Challenge and Solution

This chapter presents challenges and solutions of petroleum well operated in a deepwater environment. The discussion is based on practical field cases studied to obtain information dealing with deepwater operations. In this thesis, four main operational phases are considered for the analysis of wells life. These are exploration, drilling, completion/production and finally the plug and abandonment phase. In addition, corrosion issues are also discussed which some of the most challenging issues are at any phase of operations. Only phases that deals with the challenges and the currently available technologies in this industry will be considered in this thesis.

3.1 Exploration Phase

Seismic exploration is the primary phase prior to drilling operations. Exploration below salt formation was almost not possible until the 1980's because of the difficult challenges illustrated in figure 3.1 [14]. The region with highest concentration of salt structures which known as the triangular area, consists of the GOM, the West Africa offshore basins, and Brazil. The reservoirs in this triangular area are located in the subsalt layers or pre-salt layers, which are approximately 800 [km] wide and it offers a great potential of hydrocarbon reserves [15].

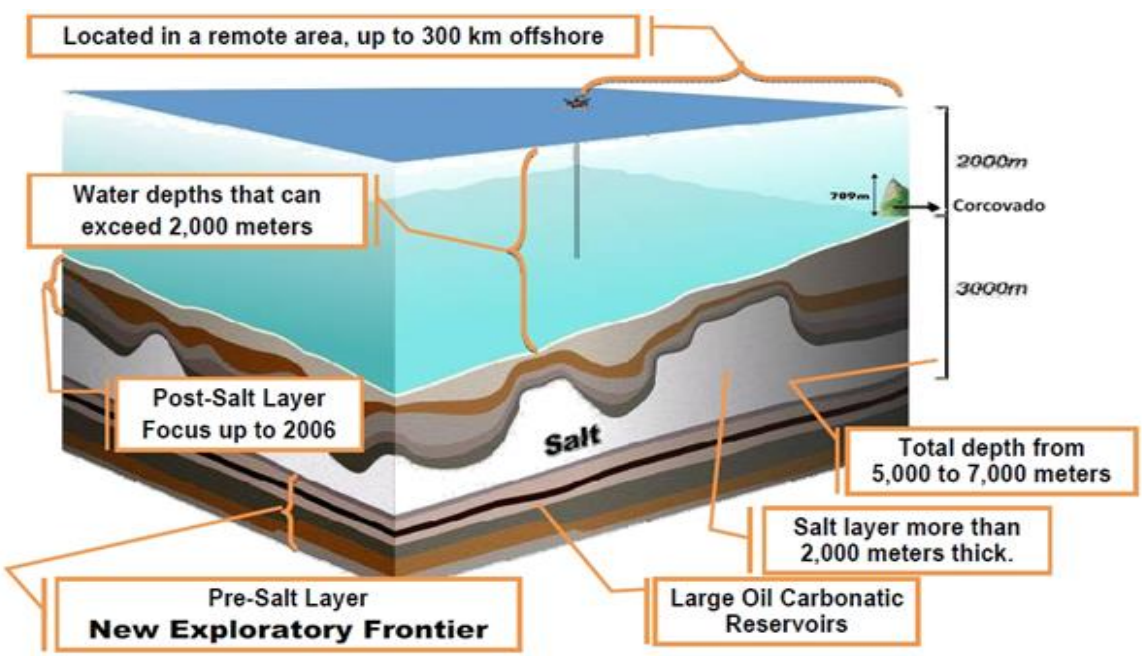


Figure 3.1 advanced area in reservoir located in salt formation. [15]

3.1.1 Challenge and Solution

For a successful petroleum discovery, the quality of the subsurface imaging is essential. This quality of sub surface imaging depends on factors such as noises and the appropriate velocity model. A processing scheme is a key factor for inverting the correct reflectivity of geological formation. The structure of salts in a formation acts as a barrier which causes seismic energies scattering that makes the resulting data quality poor and thus imaging would be a difficult task. These challenges are observed mainly in deepwater drilling environments where the pre and post-salt exploration activities are conducted. Since reservoir targets are based on seismic data, it is necessary for drilling a reliable and properly interpreted formation. Drilling into the certain salt formation can lead to a well blowout if the proper seismic imaging is not performed and this can result in a enormous economic loss. In standard, there are three-migration technique used such as *Wave Equation Migration* (WEM) technique, kick off and beam migration. Due to salt bodies and complex structures, imaging with the processing algorithms is not sufficient.

New processing technique such as *Reverse Time Migration* (RTM) is producing seismic imaging of higher quality from conventionally acquire survey. Conventional seismic image processing techniques assume that the sound wave would take a mere path in travelling to the reflector. That leads to higher scattered energy that is being regarded as noise. The conventional method was inefficient when it came to dealing with wave transmission through salt where energy scattering takes place in the areas shown in figure 3.2 and 3.3. The idea behind the new technology, RTM, utilizes a two-way wave equation migration that gives more accurate imaging which subsequently leads to the production of processed data, with better quality and bellow areas of the complex structure. Inversion and seismic analysis are important for success rates of explored regions such as 300 km from land and 7 km depth [15], [16].

Figure 3.2A displays the conventional imaging obtained from a WEM technique that results in poor imaging of salt body and nearby reflector. Figure 3.2B shows the results of reverse time migration that improved the resolutions of the salt and reflectors producing an appropriate picture of the formation. Figure 3.2C and Figure 3.2D show an example of migration technique implemented on a synthetic model with beam and RTM respectively. The result with the RTM shows good imaging quality. The application of RTM processing solves the deepwater pre-salt and sub-salt formation imaging problem. Figure 3.3 also illustrates the imaging power of RTM on deepwater seismic data.

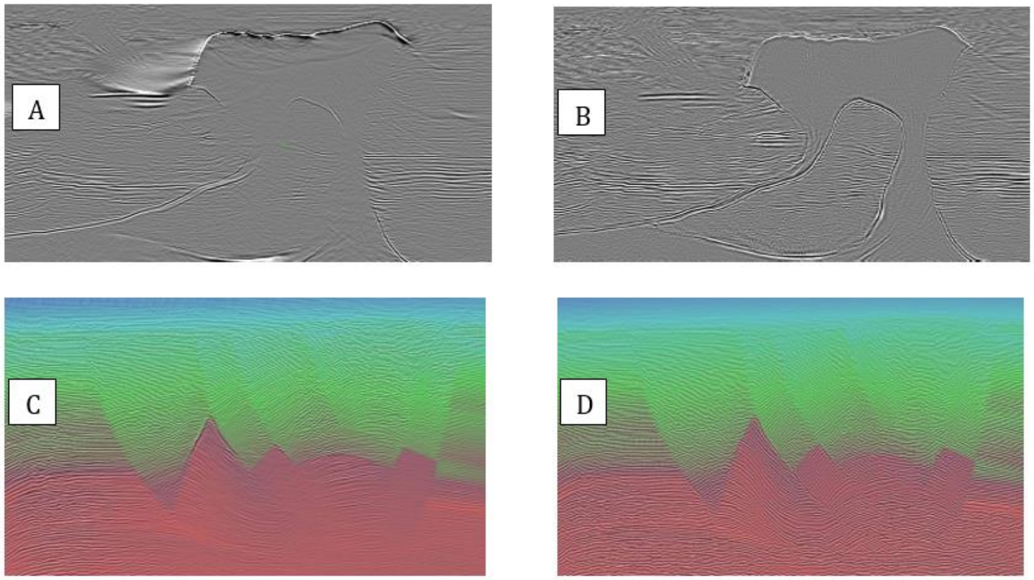


Figure 3.2 (A) Conventional image, (B) RTM, (C) beam migration, (D) RTM migration on TTI synthetic model. [16]

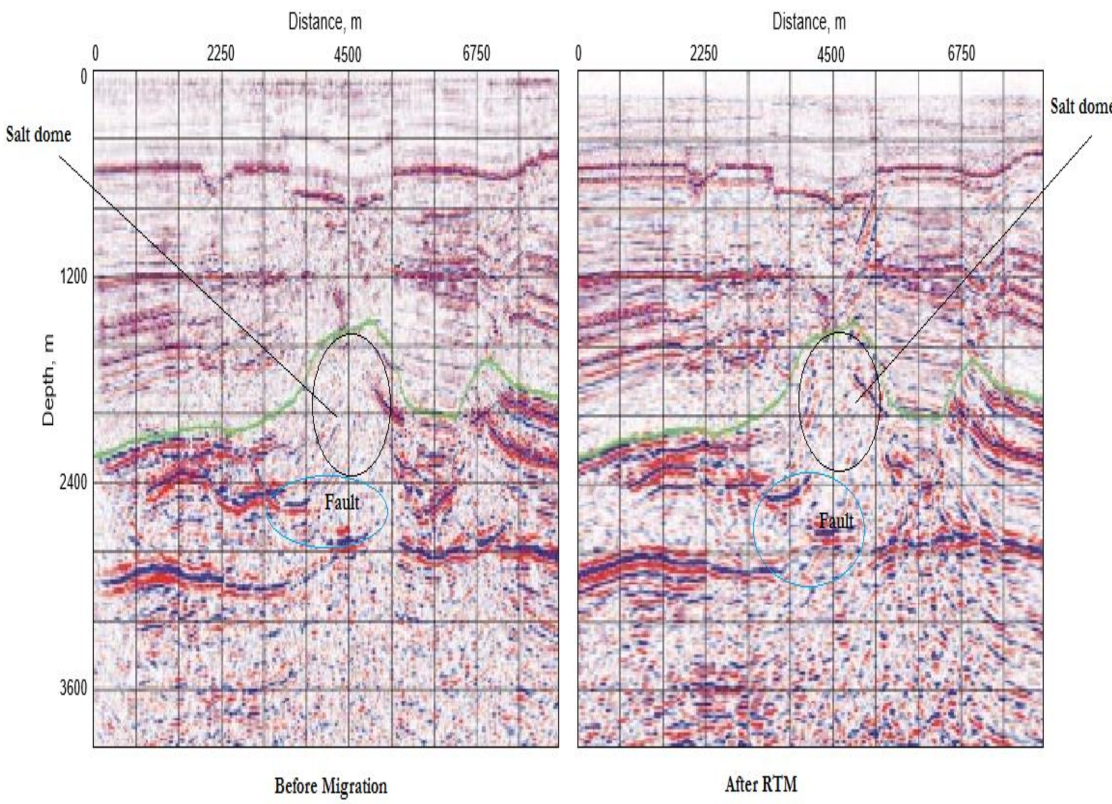


Figure 3.3 Seismic imaging in post stack and pre stack using RTM technique. *[14]*

Drilling Phase

Drilling is the process of creating a hole in order to connect surface with the reservoir. For this, several equipments are used. In this section, drilling phase's related challenges in deepwater wells will be presented. The deepwater drilling operation is expensive. Challenges and solution of drilling related issues to be presented are; drilling rig, riser, drilling fluids, kick, cementing, annular pressure buildup, and drilling through salt formations.

3.2.1 Drilling Rig

Deepwater offshore platforms is expected to grow from 3% in 2010 to 10% in 2020 [17]. Currently, there is a different type of floating deepwater units in the market which including Tension *Leg Platform* (TLP), *Semi-Submersible* (SEMI), *Floating Production, Storage and Offloading* (FPSO), *and Single Point Anchor Reservoir* (SPAR) [17]. The development of different platform over time is shown in figure 3.4. This chapter briefly presents the key characteristics of the various concepts and an overview of the limitations and solutions associated with challenges that the rig will face during their operations.

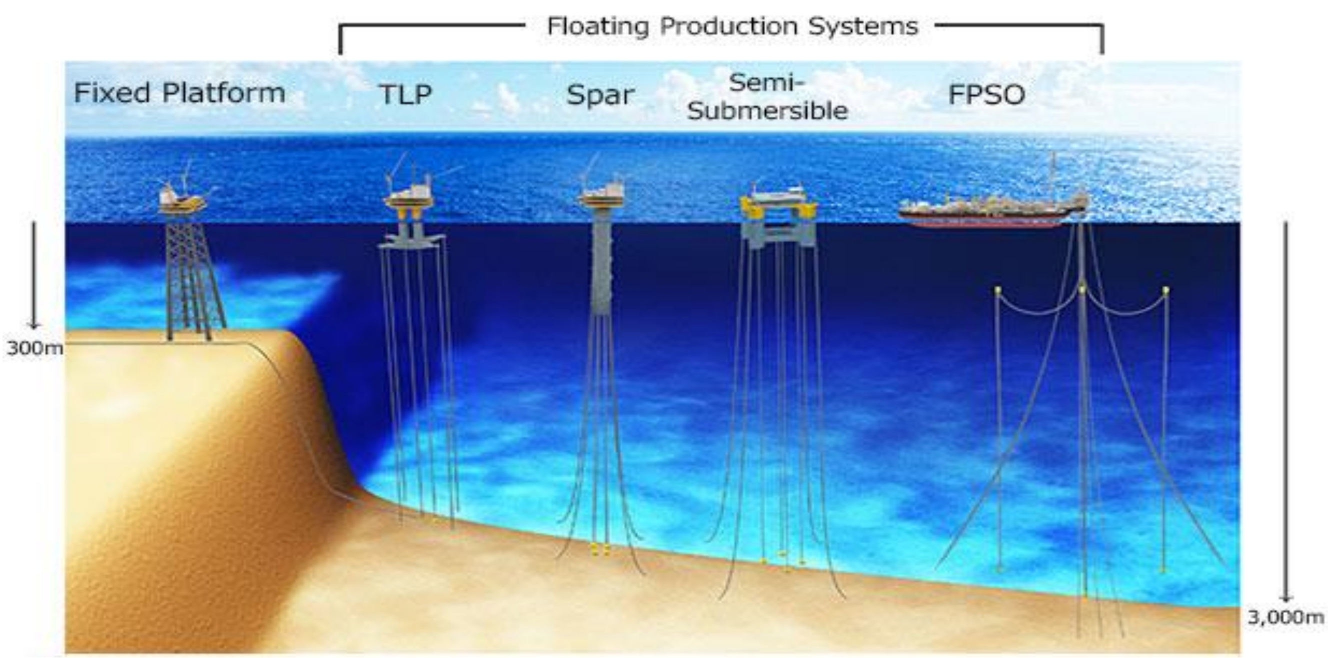


Figure 3.4 different type of offshore drilling rig. [82]

3.2.1.1 Tension Leg Platform (TLP)

TLP is originally developed as a permanently installed drilling and production platform, which was designed as an alternative solution to a fixed platform that had a problem operating in the deepwater environment. TLP's are moored to the seafloor by vertical tension legs or tendons. The hull creates enough buoyancy to hold the tendons under tension as well as supporting the load. Due to technical design limits of the tendons and high cost, it can be considered as a challenging problem for deepwater [18].

3.2.1.2 SPAR

SPAR is a floating oil platform that has a shape as a cylinder, and is vertically moored on the seabed. SPAR platform can be used as a wet and dry tree host plus as a hybrid dry tree and wet tree host. Spar platforms create excellent flexibility with respect to drilling, completion as well as production procedures. Since many parts of the SPAR structure are submerged into the water, therefore waves, wind and current activities can be less affected by it.

There are three SPAR design generations namely classic, truss and cell SPAR. Each of them addresses a range of functionality as well as operation environment [19].

3.2.1.3 Semi–Submersible

Semi-submersible, which is a *Mobile Offshore Drilling Units* (MODU), is usually a column-stabilized unit. It is made up of a deck structure with support columns that are large in diameter, and are connected to the submerged pontoons. There are different types of pontoons, such as ring pontoons, twin pontoons and multi-footing. Many of these semi-submersibles consist of bracing members that are connected to the columns at specified areas and thus provide structural integrity plus improving the water plane inertia. Normally unit is deballasted to bring it back to pontoon draft for transit propose in order to reduce the drag effect during towing of the units to another location. At this draft the pontoons are below the water surface to handle seakeeping aspects. Usually, most of the semi submersibles are moored to the seabed, but some also apply dynamic positioning (DP). That allows the vessels to keep in-place by thruster for better stability in harsh environment conditions [18].

There are several generations of semi submersibles in the market today. These are classified based on building year, technology deck capacity, and water depth capacity (see Table 3.1). The latest development of semi-submersibles uses dynamic positioning and anchors-like conventional mooring systems. The newer generations are capable of operating in a harsh environment including inclement weather [3].

Table 3.1 Annual improvement of semi -submersible rigs. [3] [20]

Generation	**Building period**	**Water depth up to $[ft]$**	**VDL $[mT]$**	Day Rate $[UDS]$
$\mathbf{1^{th}}$	1962-1969	1000	1000-1200	-
$\mathbf{2^{th}}$	1970-1981	1500	2 300-3 300	270 000
$\mathbf{3^{th}}$	1982-1986	3000	3000-4000	300 000
$\mathbf{4^{th}}$	1987-1998	6000	3500-5000	370 000
$\mathbf{5^{th}}$	1999-2004	10000	5000-6500	450 000
$\mathbf{6^{th}}$	2015-2014	11000	7000-8500	500 000
$\mathbf{7^{th}}$	2015-	12000	-	-

3.2.1.4 Floating Production Storage and Offloading (FPSO)

FPSO is usually built with a ship-liked structure, and its deck has a processing plant. It has flexibility when it comes to selecting the required mooring system for deeper waters. When operating in harsher environments, it is installed with a turret that can provide the connections between the unit, riser and the mooring systems. FPSO can also be equipped with disconnected mooring-riser systems that can be very advantageous for regions with cyclonic activities or icebergs. That gives it the ability to disconnect from the risers. It is therefore relatively simpler to relocate to a safer location until conditions become favourable for the safer return to its original location to carry out the operation. For milder sea conditions, simpler arrangements can be used, such as spread mooring, when the conditions do not require more sophisticated mooring systems [21]. The anchoring positions that is fixed to the seabed are important criteria to keep the FPSO on location.

Typically, there are two basic design criteria to be considered in the different geographic area. These are winter storms and revolving tropical storms. The mooring system is designed in such a way to survive in a 100 –year return period in respect to wind, current, and wave of specific project size. Table 3.2 is an example of a 100-years return period for design wind speeds in GOM [22].

Table 3.2 Environmental criteria in GOM (Winter Storm). [22]

Wind $[knot]$	**Wave** $[ft.]$	**Peak period**$[second]$	**Current** $[knots]$
108	40	13-18	3.0

Traditionally, spread mooring system have been used in mooring ships with a storage capacity. This system uses multiple anchor lines that extend from the bow to the stem of the hull, which will moor the vessel to the seabed in a fixed or slightly variable state of motion. With this type of system is used, the weather condition directly influences the performance, hence, they are not an effective system to be used in regions that have variation in wave, wind and current. It will subsequently create a heavy load on the anchor and lead to the excessive motion on the platform [22]. The new concepts such as *dynamic position* (DP) has been in the market for several years.

3.2.1.5 Drilling rig challenges and limitations

There will be several difficulties and constraints that will be encountered when the different rigs are being used for drilling operation. These challenges and limitation are summarized in Table 3.3.

Table 3.3 Deepwater drilling rigs limitations. [18]

TLP	• Weight sensitive. • Full-size TLPs are not appropriate for use on Ultra-deepwater fields. • Can not be easily moved from one location to another due to the required permanent, vertical anchor lines. • Not sTable without the vertical anchors.
SPAR	• Requires high construction and transportation cost because of its large structural dimension. • High installation cost because of offshore topsides-hull mating. • Limited deck size. • When SPAR is present in extreme environmental conditions, the resulting heel angle can be very large.

SEMI	• Weight sensitive due to low flexibility with respect to deck load. • High capital expenditure. • Complex ballasting system • No-oil storage capacity.
FPSO	• Must use subsea trees. • The turret system can act as a constraint on size and number of risers. • High level of dynamic motions when exposed to extreme weather conditions. • Require offsloadings shuttle tankers in order to transport the produced oil to the shore terminals. • Additional crew and marine equipment are needed.

3.2.1.6 Dynamics Position (DP) Concepts

Dynamic position (DP) system is a computerized system that holds the vessel in the desired position by using its own propelling system, rudders, and active thrusters. It is used on FPSO and semi-submersible for exploration and operation purpose for the deepwater resource. It helps semi-submersible and FPSO to withstand harsh and unstable sea condition. The internal force combined with the external forces that act on the vessel create six freedom movements that are a roll, pitch, yaw, surge, sway, and heave as shown in Figure 3.5 [23], [24].

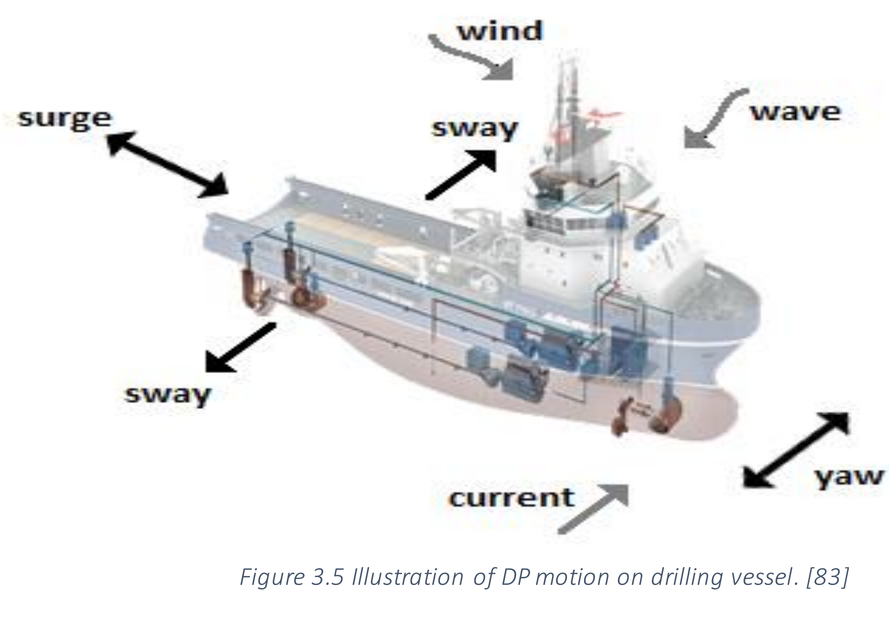


Figure 3.5 Illustration of DP motion on drilling vessel. [83]

Drive-off and *Drift-off* are two types of failure losses experienced by DP. A *Drive-off* happens when the positioning system steers the rig away from its location. When drive-off takes place, the rig is moved to another position away from the well. In this case, the *Blow Out Preventer* (BOP) must seal off the well and the riser should be released. This will prevent the wellhead, the riser system and the casing from becoming damaged. A Drift-off takes place when there is a power-loss on the rig and the environmental forces drift it away from its original location. In this case, the riser must also be released again to have well integrity protection [24].

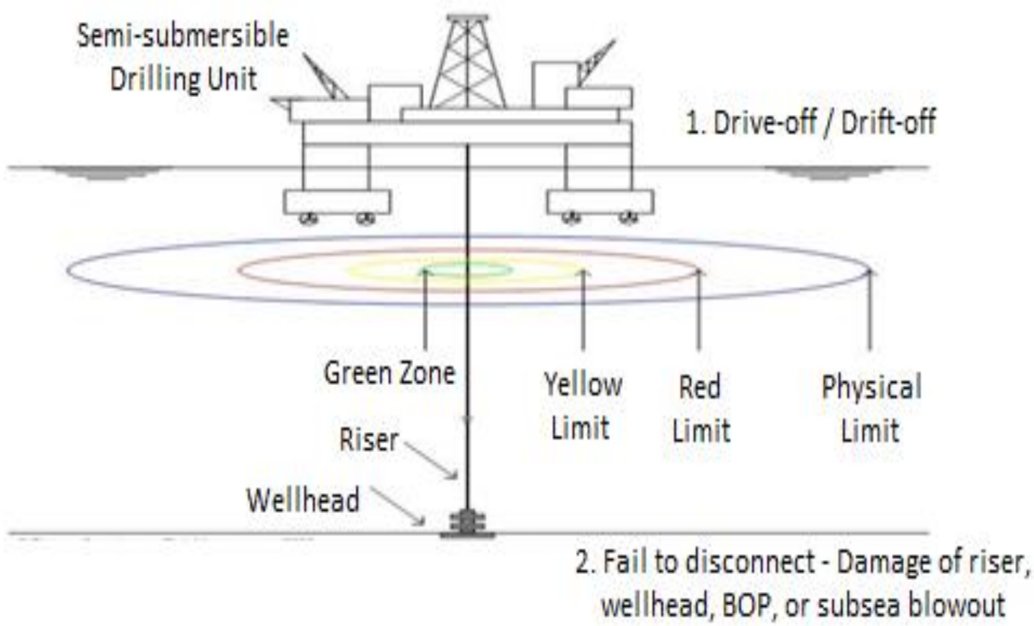


Figure 3.6 Position loss in DP system. [78]

Figure 3.6 depicts an example for a drilling rig (semi-submersible) that is operating under normal operating conditions, which shown in the yellow zone. When the thrusters cannot hold the rig within this yellow zone, then it can drift off towards the edge of the red zone.

The position loss of drive-off vs. drift-off frequency can be calculated using the risk model for marine operations as shown in the formula below [24]:

$$P_{accident} = P_{position\ loss} \times P_{failure\ of\ recovery}$$

3.2.2 Drilling riser

Deepwater drilling riser is a tubular equipment that connects drilling platform with the subsea wellhead and the BOP to the drilling rig [25]. It also transports the return drilling fluids and the reservoir hydrocarbon to the platform during drilling and production phases.

3.2.2.1 Challenges

Riser systems experience challenging issues; the factors that affects the state and integrity of risers are due to *Static and Dynamic* factors:

- *Static factors* –The riser is filled with drilling mud which causes a good significant static stress on the pipe itself as well as on the vessel that holds it.
- *Dynamic factors* - These factors are current, and wave which are illustrated in figure 3.7.

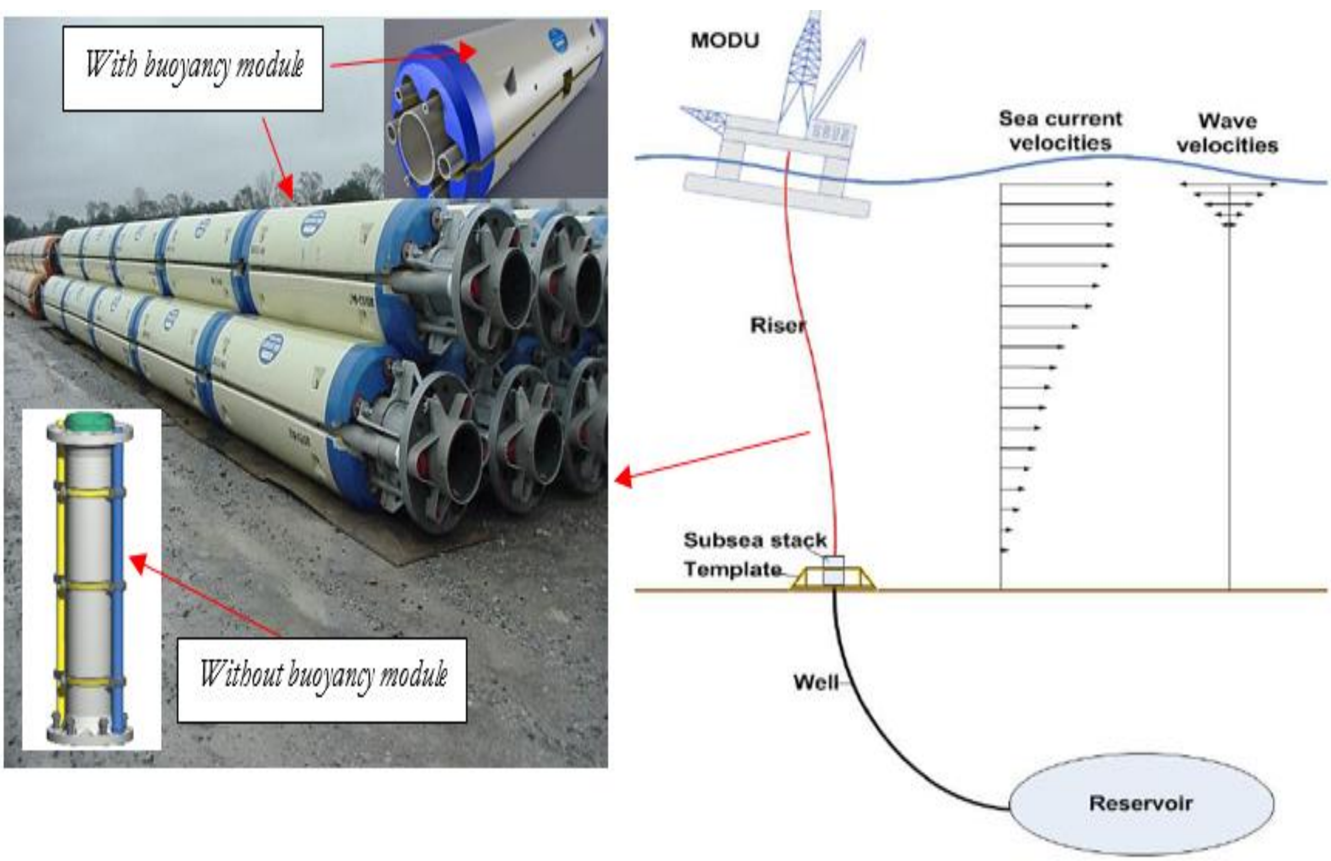


Figure 3.7 Loads on riser. [79] , [80], [81]

Loads that acts on riser during drilling and production are;

Waves

- Wave induced fatigue on the risers
- Direct wave forces on the risers
- Platform motions on the risers. These platform motions are induced by heave, pitch, roll and sway.

Current

- Current load (along the waves)
- VIV on the risers (fatigue)
- Slow drifting of the platform (vessel offset) [25]

The effect of current on the risers in Ultra-deepwater wells is one of the biggest challenges. When riser exposed to currents that generates *Vortex-Induced Vibrations* (VIV) which increase *fatigue damage*, and increase the *In-Line drag*. Increasing in drag, will resulting in increased flex joint rotations. The effect of VIV on the riser and the riser's response is dependent on many factors. Some of these factors are:

- *The material and shape:* Different materials and the riser's shape have different reactions in respect to vibration.
- *Riser length:* The effect of deep current becomes more visible, as the depth of the exploration and extraction increases,
- *Riser termination*: The seabed condition at which the riser stops varies in its Condition. In return, it affects the response of the riser to VIV.
- *Current directionality*: The variation in current direction creates further obstacle for the Risers and may induce fatigue speedup [26].

If the riser consists of joints without buoyancy and contains heavy mud, a higher top tension is required to carry the weight of the riser and give enough tension at the *Lower Marine Riser Package* (LMRP) connector [25].

3.2.2.2 Solutions

3.2.2.2.1 A-Design based solution of Risers

To handle the challenges that are encountered in various sea conditions with respect to the riser, the industry has invested heavily in different riser designs for drilling and production operations. The choice of design depends on the particular well conditions such as , variations in their (risers) usage, advantages, and costs. The type of designed risers are:

- *Top Tensioned Risers:* these types of risers are mainly suitable for TLP and SPAR. TLPs are supported at the top side by either hydraulic heave compensator system or by buoyancy tanks. [26].

- *Flexible Risers*: this type of risers are suitable for shallow water conditions and cyclonic conditions although there is a more recent requirement for deep sea drilling. The additional required flexibility is gained by adding further buoyancy models see figure 3.7, such as forming riser loops, and uncoupling the bottom section of the riser from the floating unit motions [27].

- *Steel Catenary Rise*rs: SCR riser are usually fitted with an anti-VIV device this type of risers has a rigid steel pipe with considerable bending stiffness. The shape of which is controlled by weight, buoyancy and hydrodynamic forces of the surrounding environment, namely currents and waves [26].

- *Hybrid Risers:* this type combines two different systems, such as steel pipe and flexible pipe technologies; which allows the riser to absorb dynamics motions of the riser. While the vertical side can be either vertical leg or SCR buoyed below the surface of the sea, while the flexible section is used in completing the fluid flow from the subsurface to the *Floating Production Unit* (FPU) [27].

3.2.2.2.2 Alternative materials based solutions

Traditionally, steel is used for riser manufacturing. As the depth of deepwater increase, the longer steel longer riser will be needed. The Longer steel-based riser has a higher effective tension. Due to weight, corrosion effects, and wear and fatigue issues related to steel riser, alternative structural materials are required. The alternative solution for steel is the use of *Aluminium* (Al) and *Titanium* (Ti) based risers. The selection of these materials is due to their physical and mechanical properties, the greater strength-to-weight ratio as well as resisting corrosion. Table 3.4 shows the elastic and physical properties of these materials. This section will examine the description, advantages and disadvantages of aluminium and titanium in comparison with steel [28].

Table 3.4: Mechanical and physical properties of Steel, Aluminum and Titanium properties [28]

	Unit	Steel Grades	Aluminum Alloys	Titanium Alloys
Density	(kg/m^3)	7850	2800	4410
Yield Strength	MPa	931	330	827
Young Modulus	GPa	210	72	114
Poisson Coefficient	-	0.3	0.28	0.34
$(\sqrt{EI\rho})_{steel} / (\sqrt{EI\rho})_{materi}$		1	2.9	1.8

3.2.2.2.3 Aluminum (Al)

Aluminum as a drill pipe material is highly suitable material for manufacturing of tubular structures, with higher strength-to-weight ratio compared to steel of around 2.25 time's lower density. It allows a reduction in structural weight of the equipment compared to its counterpart that is made from steel. This reduction in weight allows ease of transportation and handling of the tubular, some of the advantages and disadvantages are summarized in Table 3.5 [29].

Table 3.5 Advantages and disadvantages of Aluminum riser. [28], [29]

Advantages	Disadvantages
• The strength-to-weight ratio is much higher than steel, which is one of the main advantages leading to the development of *Steel Alloy Aluminum* (SAA), based drilling strings and riser. • Better insulating material to prevent cold-shortness especially in cold Arctic environment. • It's hydrogen sulfide and carbon dioxide resistant properties prevent hydrogen embrittlement. • Highly resistant to corrosion. • Some natural characteristic of aluminium is that it can be easily bent, pressed, and welded. • Because of its low density, the weight per unit length of aluminium pipe is about half of that of steel. • Smaller drills rigs for drilling deeper wells can be used because of its low hook load weight. • The lightweight of aluminium allows for an increase in pipe thickness and therefore compensate for strength loss in the walls. • The cross-sectional area of the annulus can be decreased because of the bigger outer diameter of the aluminium drill pipes. This increase fluid velocity and therefore decreases the pressure inside the drill pipe and as a result there is no need for mud pump and thus thereby decrease the drilling operation cost. • There is an increase in buoyancy factor due to the low aluminium drill pipes weight, hence decreasing the bending and axial forces. This creates safer drilling for wells with large angles of inclinations.	• Aluminium pipes are light because of its low-density characteristic and therefore it is less resistant to burst and buckle phenomenal. • It is less stable at higher Temperature. Due to the fact that the riser is exposed to high thermal expansion.

3.2.2.2.4 Titanium (Ti)

Titanium drill pipes are mostly utilized for ultra-short radius drillings. This is due to their rotation capabilities through bends of these types of wells without high-stress cycles failure. Selecting titanium for deepwater applications must be done with consideration for the transported fluid, loads, and Temperature as well as possible installation and operation failure modes [30]. Titanium has a number of attributes that makes it more optimal that is viable over steel with a short radius drill. Some of the advantages and disadvantages are given in Table 3.6.

Table 3.6 Improvement and limitation of Titanium rise [29] , [30], [31].

Advantages	Disadvantages
• Ti has about half the density of steel. Its density is 4.48 sg which means it is light in weight thus leading to less weight for dimensions, tension, wellhead, and topside equipment. It also eliminating flex joints and the buoyancy elements. • It has a high yield strength about 759 MPa and therefore is good for high-pressure risers. High yield strength decreases riser wall thickness, which in turn decrease its weight. • It has a small elastic modulus which results in low stiffness and induced bending moments and thus it leads to cost reduction by eliminating flex joint deployment. • It has good fatigue properties and high endurance limits and is therefore functional, operational, and flexible in terms of challenges for the drilling riser. • It has high corrosion resistance.	• It is costly to use it.

It is also reported that drilling riser wear is a critical issue in a deepwater environment. According to the US, *Mineral Management Service* (MMS), flex ball joint angle of the riser is 2° from vertical, as shown in figure 3.8. As discussed earlier, the alternative materials such as titanium have better properties than steel. It has more flexibility, lighter weight, and are much stronger. The application of titanium riser also has disadvantages. The main reason is that it is susceptible to wear since it flexes more than the steel riser does.

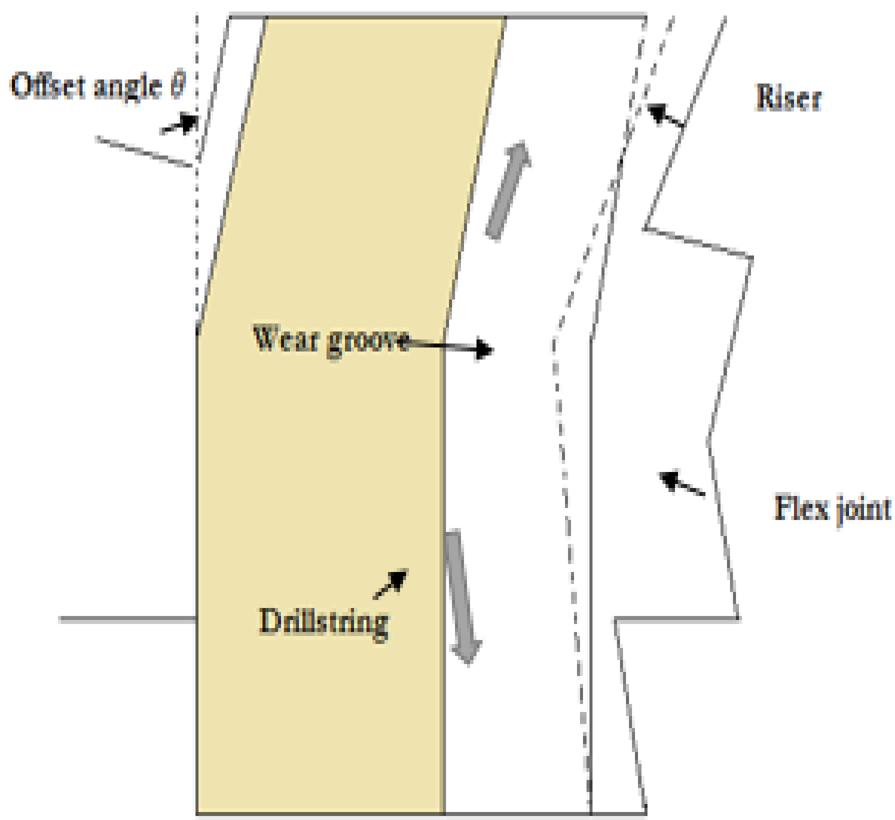


Figure 3.8 Angles at the flex joint cause excessive casing wear in the lower joints. [32]

However, the problem of wear can be managed by lining internally with thick rubber (0.25 -0.50 inch). This method is implemented in Heidrun tension leg platform, which used titanium riser [32].

3.2.3 Drilling Fluid

Drilling fluid is an important aspect of drilling operations. There is no single type of fluid, which is suitable for all types of operations. The choice of drilling fluid during drilling is based on the project, operational requirement, and bottom hole Temperature. During the planning phase, it is important to have the appropriate consideration and accurate knowledge of fluid behaviour in order to manage safety, HPHT conditions, loss zones, problematic shale sand hence cost.

The Temperature in a well is varied from cold Temperature at the seabed near freezing and high Temperature above 300°F, high-pressure greater than 10 000 [ft.] [6]. These thermodynamic states have an impact on the drilling fluids such as rheological properties, viscous-elasticity, density and other physical and chemical properties

3.2.3.1 Challenges

The rheological related challenges reflected on hole cleaning, hydraulics, fluid jellification at low seafloor Temperature and reservoir invasion. The falling in Temperature while drilling result in rapid cool down for the drilling fluid, that leads to significant increase in the viscosity, and changes the density of the fluid. In the deepwater well when the pore pressure and fracture pressure is small; (ECD) can be lower than pore pressure or exceeding fracture pressure. This creates numerous challenges for the operation such as kick, non-productive time, borehole collapsing and influx of formation fluid, and problem [33]:

3.2.3.2 Solution

Flat rheology (FR) system is a recently developed system that uses a single emulsifier component in providing both, emulsification and surface wetting. Thus improving the emulsion stability and enhancing the thermal stability as well as fluid lubrication. Several fluids components that influence the ability to generate a flat mud system are illustrated in the Table 3.7.

Table 3.7 Typical ingredient for synthetic mud in FR and Conventional rheology system. [33]

Additives	"Flat Rheology"	Conventional
Base synthetic	X	X
Weigh material	X	X
CaCl2 Brine	X	X
Lime	X	Low
Primary Emulsifier	X	
Secondary Emulsifier	X	
Fluid loss control material	X	
Organophilic clay 1	Low	X
Organophilic clay 2	Low	
Bridging material	X	X
Polymeric rheology modifier	X	
Thickening agent	X	
Dispersant/Conditioner	X	

Flat rheology drilling fluid system can be formulated for a deepwater application using 18lb/gal at the peak Temperature 350°F. This has been leading to a reduction of non-productive times in difficult regions of GOM since 2004, by achieving the following conditions:

- Keeping the fluid properties of density and viscosity constant.
- Removing the cutting with high ROP thus maximizing hole cleaning.
- Gelation reduction near seabed in low-Temperature zones.
- Reducing the potential circulation loss by improving ECD.
- Higher hole cleaning efficiency during reduced torque and drag in higher Temperature zone near the bit.
- Barite suspension for sag control.

Figure 3.9 shows the variation in Temperature during the drilling operation, to achieve a target depth as a function of plastic viscosity and yield point for flat mud system. There will be a change in both, viscosity and yield point of the conventional system as Temperature varies. While it remains constant for a flat rheology system [34].

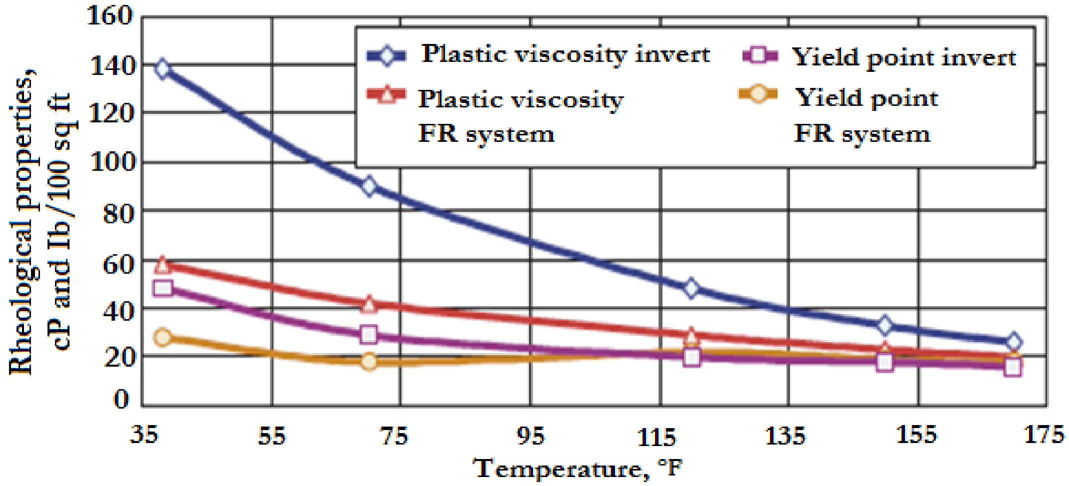


Figure 3.9 Rheological profile for a conventional and Flat Rheology. [34]

3.2.3.3 Case Study – Offshore Sabah

Flat rheology system has also been used for a deepwater offshore well in South China. The chart in figure 3.10 shows the reduction of mud losses due to flat rheology drilling fluid. The data present a range of hole sizes were significantly reduced, by using flat rheology fluid system. Reductions of around 90% in mud loss for 8-1/2 inch and 6 inches [34]. The holes experienced almost no losses resulting in mud reuse, after centrifuging for a number of subsequent wells.

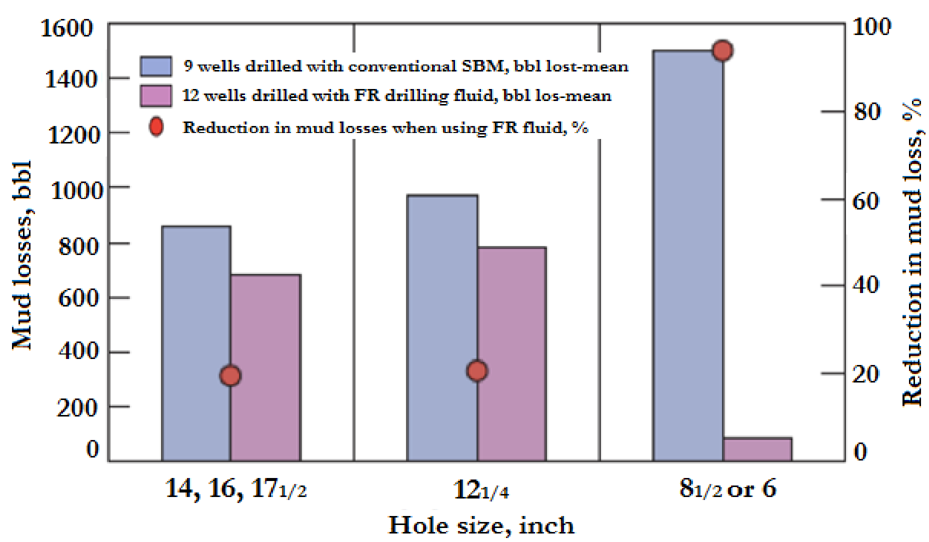


Figure 3.10 FR Vs Conventional mud loss reduction. [34]

3.2.4 Kick and Cementing

Drilling operations are particularly challenging in depleted reservoirs, HPHT and deepwater wells. The risk of kick and cement slurry problems increases when the well pressure crosses operational windows, as there is a small margin between pore pressure and fracture pressure, shown in figure 3.11. This section will suggest suitable technologies for these challenges.

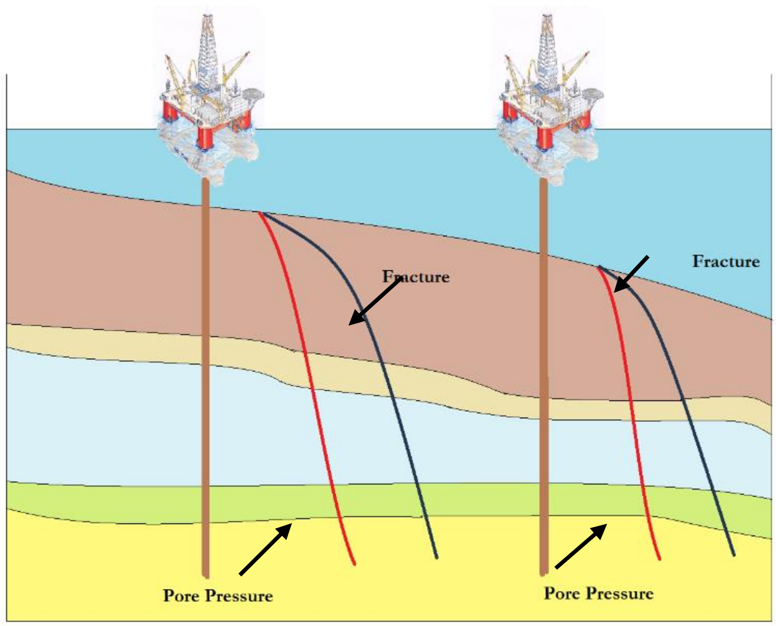


Figure 3.11 Formation profile of shallow and deepwater. [75]

3.2.4.1 Challenge

- Low Temperature at Seabed causes the cement to take longer to reach the desired compressive strength.
- Near wellbore instability will lead to hole washout due to shallow gas hydrates.
- Due to the narrow operational window, there is a possible of kick, and well instability such as well collapse and well fracturing.

3.2.4.2 Solution - Managed Pressure Drilling (MPD) and Cementing

These methods are safer when operating in tight and narrow operational window. According to *International Drilling Contractor* (IADC), MPD [35]: it is all about controlling annular pressure precisely so that one can drill near formation pressure. For this, there are appropriate surface and downhole equipment, which are integrated with the conventional drilling rig. During MPD method, the bottom hole pressure is calculated as: [36]:

$$P_{bottomhole} = P_{hydorostatic} + P_{friction} + P_{choke}$$

The conventional method bottom hole pressure is calculated as:

$$P_{bottomhole} = P_{hydorostatic} + P_{friction}$$

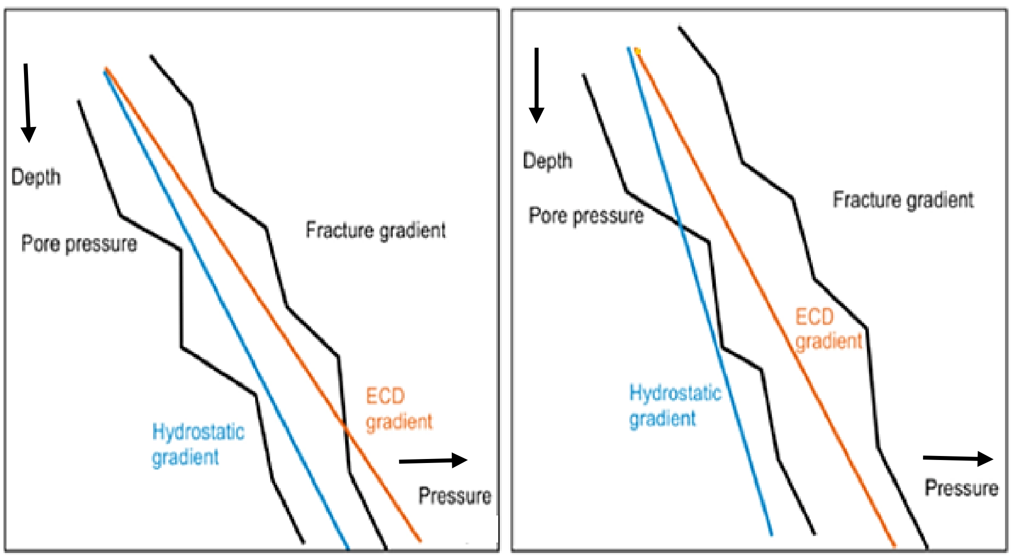


Figure 3.12 MPD and conventional system. [36]

As indicated in figure 3.12, conventional drilling requires the mud weight to be greater than pore pressure. However, drilling with this mud fluid, as illustrated in the figure, the ECD exceeded fracture gradient. This shows that the drilling with conational methods is problematic in wells with narrow operational window, which is common in deepwater reservoir section. On the other hand, when drilling with MPD, by using lower mud weight, which is less than the formation pore pressure, and by using backpressure, one can drill the narrow window safely. On conventional drilling, MPD uses additional equipment as shown in figure 3.13.

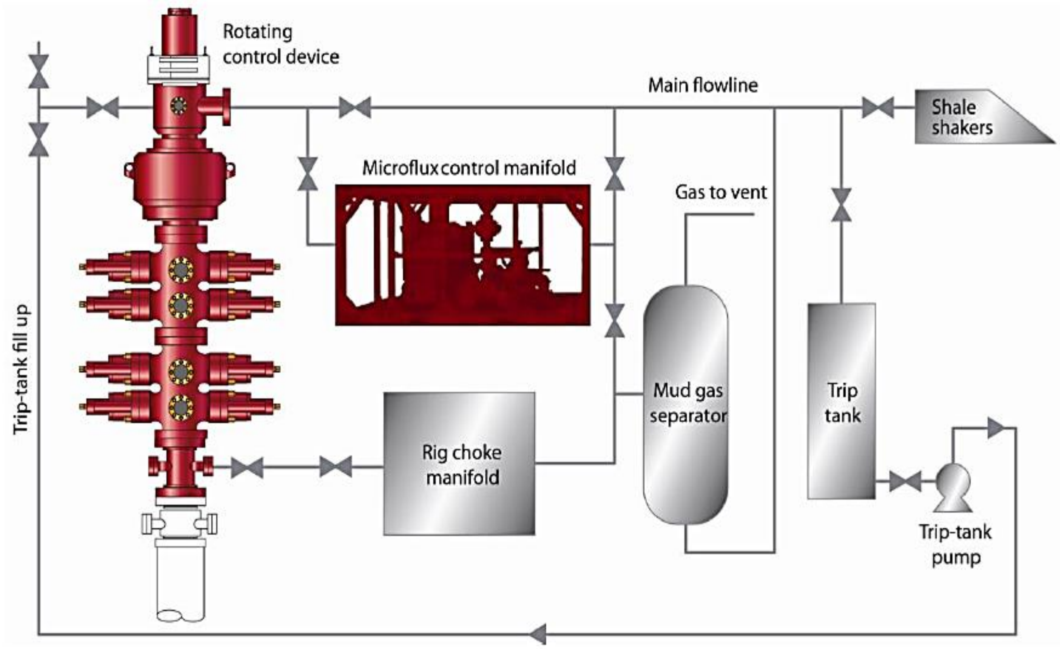


Figure 3.13 MPD equipment. [75]

The main MPD surface equipment that controls the operation and acts as maintained pressure tight barrier in the annulus is described in the following [37].

- ***Rotating Control Device(RCD)***

  RCD has a conic structure, which is made up of elastomer. During the drilling operation, the drill string is passing through the RCD and has a good tight seal between the drill string and the elastomer. The main function of RCD is therefore to divert return drilling fluid through the annulus to the control manifold and to allow drill string is rotating.
- ***Choke Manifold***

  Coke Manifold is also one of the main MPD systems, which controls back pressure. During connection period as the rig pump shutdown, the rig choke manifold will provide back pressure in order to maintain the well pressure within the safe operational window.
- ***Micro Flux***

  The return fluid from RCD will pass through the flow control units, Coriolis and *Micro Flux Control* unit (MFC). This system detects kick based on the flow in and out rates.
- ***Mud gas separator***

  When drilling near pore pressure and in a narrow window, there is a possibility for kick influx. The return mud also passes through the mud gas separator.

General Advantages of MPD system:

- Reduce NPT by maintain the well control issues.
- Reduce drilling fluid cost as the fluid losses are minimized.
- Reduce formation damage and hence better productivity.
- Increasing the ROP and increase the lifetime of the bit.
- The bottom hole pressure can be controlled during connection by activating rig choke manifold. This keeps well pressure to be within the allowable narrow window.
- Constant monitoring of the return flow and surface pressure, which leads to a reduction in chances of gas present in the riser [38].
- Requires less number of casing thus reducing the cost and operation times as shown in figure 3.14.

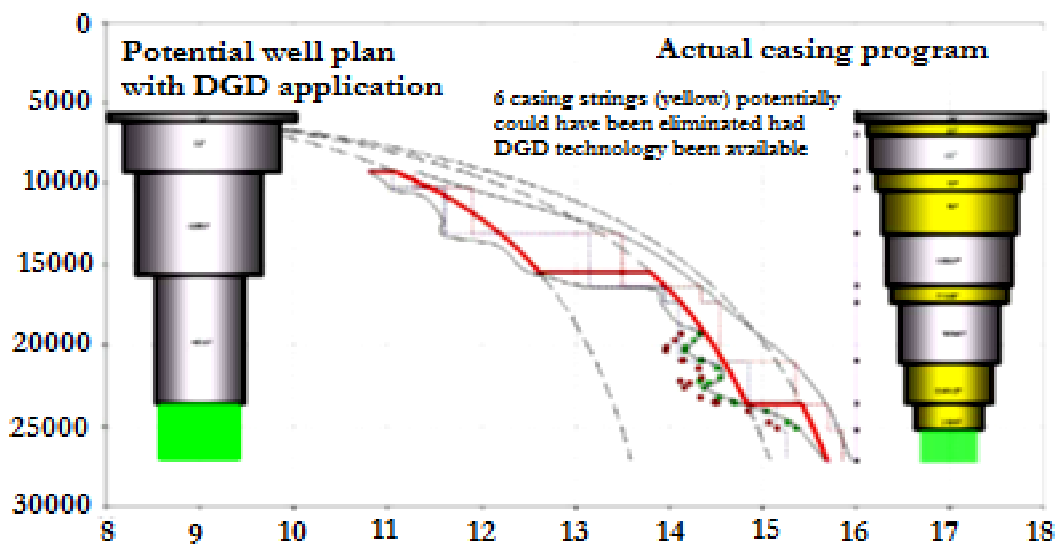


Figure 3.14 Casing design for DGD and conventional casing design. [72]

As shown in figure, conventional system uses a higher number of casings. The MPD system uses five casings, a reduction from nine. A new development of MPD used under deepwater cementing operation is *managed pressure cementing* (MPC). They use the same equipment and system by replacing the traditionally hydrostatic overbalanced with managed pressure controlled, and adjusted by a managed pressure system tied into the drilling fluid circulation system [36]. MPC is a solution for challenges related to cement slurry loss in a small window. In chapter 4, the application of MPC, and kick tolerance simulation will be presented, in addition, the effect of the HPHT drilling fluid properties will also be simulated.

3.2.5 Annular Pressure Buildup (ABP)

When the high-Temperature hydrocarbons go through the well and subsequently leads to heating up the well, this causes APB effect. As shown in figure 3.15, this has an effect on the annular space of the borehole, which might lead to sealing and filling it with drilling fluid and subsequently cause expansion. The resulting fluid expansion raises the annulus pressure to levels that might cause damage to the well when it exceeds burst strength in certain cases. The pressure can reach a high level that can cause collapse on the casing strings and in turn, the casing collapse may lead to cement/casing integrity problems [39]. The combined effect of high pressure, high Temperature and flow rate may also cause the pressure to get higher on the annulus. The thermodynamic states are the keys for the petroleum chemistry problems such as the formation of wax, hydrate and salt precipitation. It is therefore important to monitor the APB in order to maintain a long-term structural integrity.

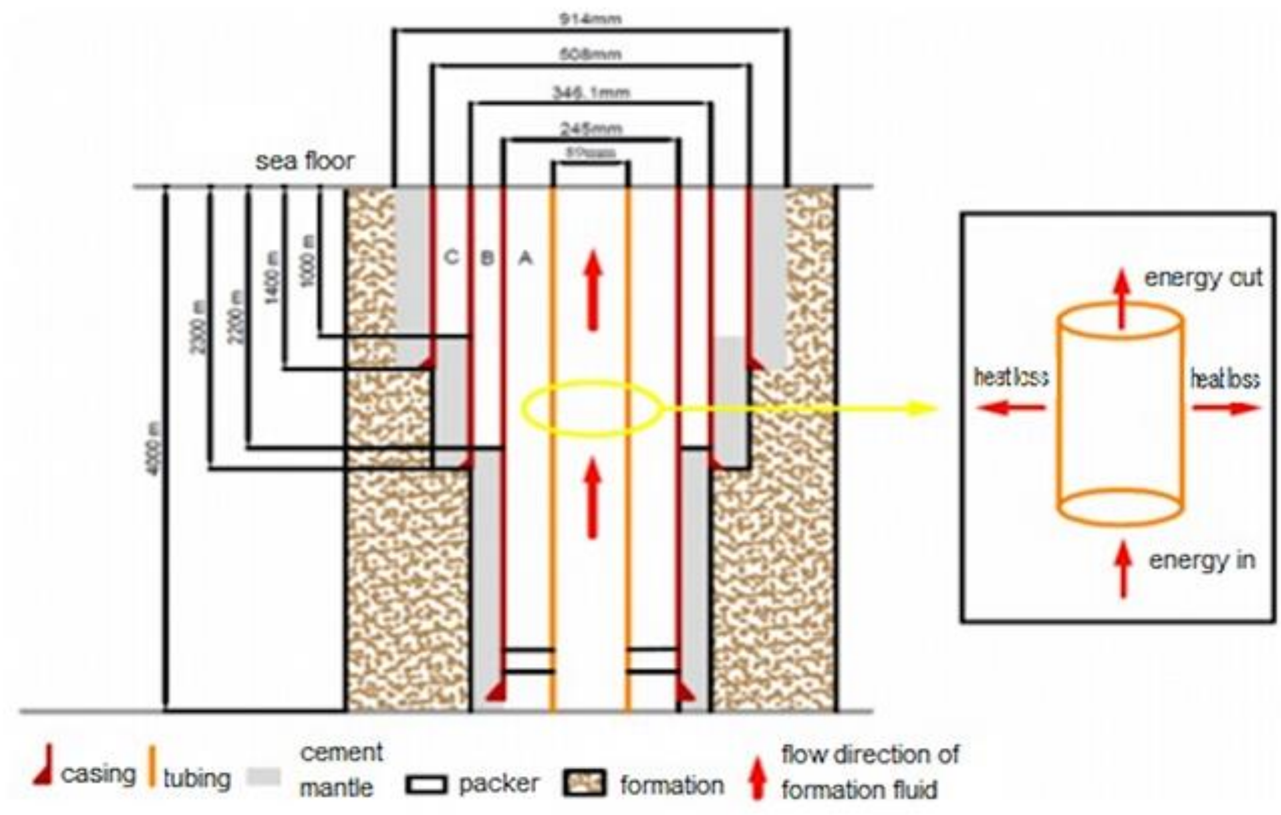


Figure 3.15 Annular Pressure Build up in deepwater well. [39]

3.2.5.1 Solution

There are a number of APB measured that is been undertaken in order to prevent potential damages caused by heat transfer. Some of the measurements range from thermal insulation pipes, heat insulating liquid, compressible foam, injection of gas into the annulus, Vacuum insulated tubing and N-isolate packer fluid. In this section, VIT and N-Solate packer fluid will be presented.

3.2.5.1.1 Vacuum Insulating Tubing (VIT):

Vacuum Insulating Tubing system is considered as a good solution for minimizing and transferring the heat radially from inner tubing to the well annular space. VIT has widely deployed in arctic and deepwater environments to reduce annulus pressure buildup as well for flow assurance.

Figure 3.16 illustrates a typical VIT system. This VIT is made up of two joints of tubing that are welded together and connected on either the inner joint or the outer joint. A port is then drilled in the outer joint and an absorbent is placed into the space. This port is drilled before the joints are welded. Next, the space that is between the joints is evacuated, heated in order to vaporise the oil and activate the absorbent, argon gas is then filled in, and finally evacuated again. When this process is completed, a vacuum plug is then installed [6].

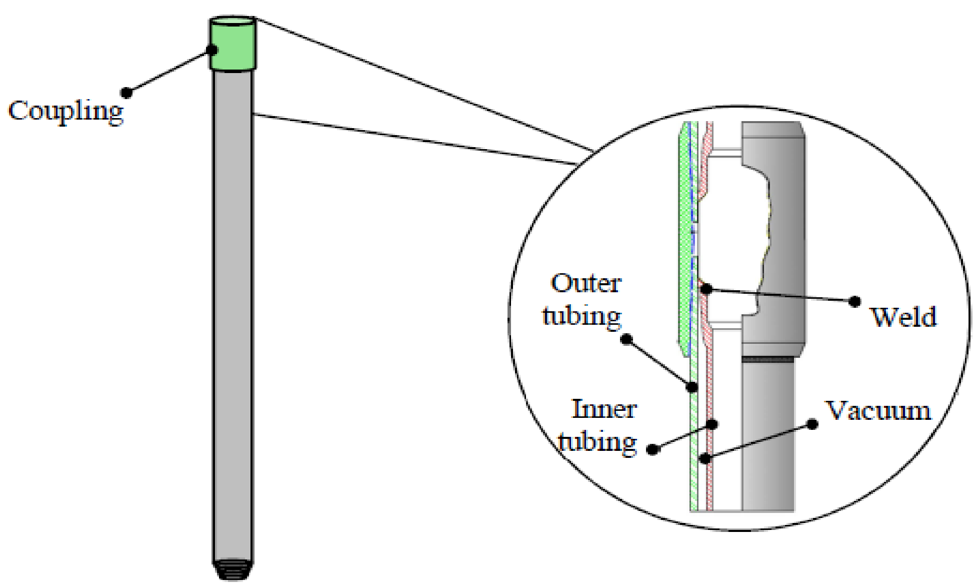


Figure 3.16 VIT system. [73]

Vacuum insulating tubing has been successfully used for the deepwater wells in GOM reaching 3 637 ft. with 31 467 ft. maximum wellbore-*Measured Depth* (MD) and a length of 5 356 ft. of VIT was installed below the mud line with the following improvement [40]:

- Reduce the radial heat transfer from the inner tubing to the well annular space.
- The vacuum created with the annulus pipe that acts as an insulator, which reduces the heat transfer through the connection.
- Eliminating the risk of Casing String Burst and collapse by reducing the APB.
- Lateral heat transfer will be reduces which happens because of high Temperature production fluid flows through annulus.
- Significant reduction of the heat that is transferred from the reservoir through the tubing to the fluid in the sealed annuli, that subsequently leads to a reduction of the thermal expansion-induced APB.
- Increasing the well productivity and reducing its cost.

Reducing the production heat transfer via the tubing to the hydrate zone and prevents gas hydrate zone from heat-up. The Prevention of gas hydrate reduces the heat loss of the produced hydrocarbon through the tubing by maintaining the produced hydrocarbon Temperature in the tubing above the hydrate formation Temperature zone.

3.2.5.1.2 N-SOLATE Packer Fluid

N-SOLATE packer fluid had been used in GOM are designed to reduce the undesired heat flow through conduction and convection mechanism. Non-aqueous oil-based systems and N-SOLATE fluids are formulated with densities of up to 15lb/gal. Table 3.8 shows the properties of three types of N-SOLATE systems and the advantages of this fluid are summarized in Table 3.9 [41].

Table 3.8 Various type of N-SOLATE Packer Fluid. [41]

Insulate packer fluid type	Density ib/gal	Thermal sTable °F
N_SOLATE^{TM} 275	8.5-14.2	275
N_SOLATE^{TM} 400	8.5- 15	400
N_SOLATE^{TM} 600	8.5 -10.5	600

Table 3.9 Advantages of N-SOLATE Packer fluid. [41]

Advantages
• They provide heat flow control from the production tubing to the outer annuli, hence reducing the pressure build and maintaining the well Temperature. • Easy to use and remove in the field due to the relatively low thermal conductivity of the gel structure that is used in the design. • Reducing the well cost and productivity increase. • High flows assurance

3.6.1.3 Production Packer Fluid VS. VIT System in Industry

Halliburton as a solution to mitigate the risks associated with well failure uses both VIT and Packer fluid systems. Table 3.10 shows the list of advantages and disadvantages of each system.

Table 3.10 Thermal Insulating system advantages. [42]

N_SOLATE	VIT
• The outer annuli is kept under control by keeping the out casing string isolated from heat • Prolonging the lifetime of the well under high production rate by reducing APB. • Saving rig time. • Easily removed from well intervention with low density of 13.lb/gal. • The gel structure can work at the required Temperature.	• Difficulties to control the heat transfer in the outer annuli heat. • Does not work in water depths exceeding 10 000 ft. • Costs more than N_SOLATE. • Large production casing is required.

3.2.6 Drilling through Salt formation

This section presents the challenges and solutions in deepwater salt formation during drilling as well as long-term effect on casing integrity. In several papers, it is documented that a wide sub surface salt formation in Gulf of Mexico, West Africa, and Brazil.

3.2.6.1 Challenges

Because of mechanical issues and high solubility, drilling through the salt formation is extremely challenging but depending on the salinity of the drilling fluid that is used.Salt formation could be dissolved resulting in a washout. One of the characteristic behaviour of salt is that it flows plastically into the well causing a decrease in well size, which is due to overburden as well as insufficient well pressure. This situation creates difficulties for running drilling equipment.

Creeping is another characteristic behaviour of salt, which is caused by a persistent load that is applied to the salt formation resulting in time dependent deformation. One challenge that is connected to creeping is that the load could be adequate leading to the casing or cementing integrity problem [14].

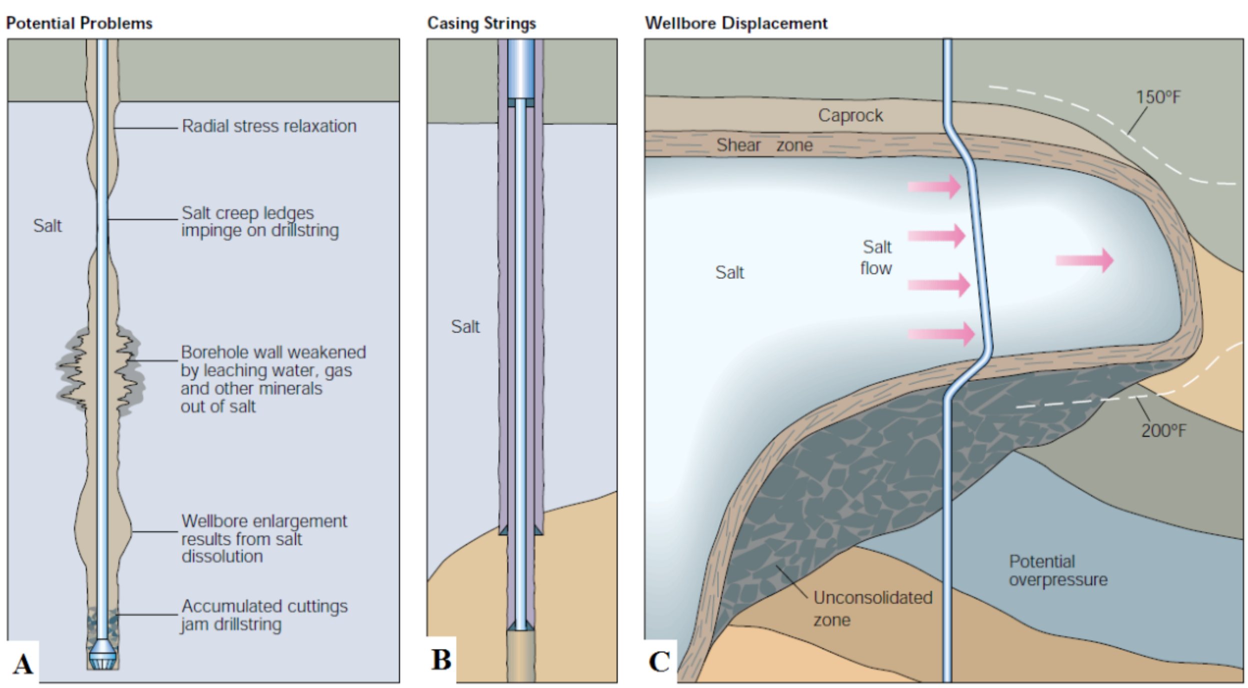


Figure 3.17 Potential problem during drilling in salt formation. [14]

Figure 3.17:

A – Washouts

Drillers have to address factors that cause open hole instability and other accompanying problems including borehole walls that are weakened by incompatible mud, restrictions, and under-gauge hole. Salt creep or enlargement due to dissolution causes these factors.

B – Casing String

To handle the effects of non-uniform loading that is caused by salt creeping, cement must be returned to the top of the salt formation. In this scenario, the liner is placed inside a cemented casing to reduce radial pipe deformation.

C - Wellbore Displacement

In this diagram, it shows that the salt movement will continue to load the casing and may result in tubular failure over a period. During the life of a well, salt movement can displace wellbore.

3.7.2 Solutions

Drilling through salty formation are managed by considering salt properties during planning and drilling operation to mitigate drilling risks through salt [14]:

- Maintain a gauge wellbore.
- Using flat rheology to minimize salt leaching.
- Use hole enlargement tools -reamers to increase annular clearance.
- Estimate salt creep rates under well conditions and plan mitigation with respect to casing design.
- Drilling with Kymera Drill bit.
- Design new cement slurry to increase well integrity.

3.7.2.1 Case Study

A case study based on salt formation in Indonesia and Santos Basin in Brazil, using Kymera Drill Bit for drilling, Supersaturated Brine drill fluid, and a new cement slurry design for corrosive environment to reduce corrosion effect on cement integrity.

Case 1 – Riser less Drilling

One good example of super-saturated fluid that are used in riser less drilling technique is found in Santo Basin in Brazil. The salt formation is located between the carbonate/anhydrite cap rock and the production formation at within a depth range of 6890 -9843 ft. [43].

Usually riser less drilling is a pump and a dump technique whereby the weight of the mud fluid is "cut - back" by using seawater. While drilling in salt formation, which uses under-saturated drilling fluid that can lead to several problems. Two of these problems that arise are hole enlargement which will cause a reduction in the quality of the cement job and reduce the ROP while drilling this type of salt formation. A way to minimize the hole enlargement is to use a super-saturated brine drilling fluid, Table 3.11 and 3.12 shows a drilling strategies and components that are used to obtain super saturated drilling fluid [43] [44].

In the case of the Santos Basin, the operations is carried out by drilling the cap rock up to 164 ft. of salt using seawater as drilling fluid to reduce required volume on drilling rig. The cut- back operations is applied further drilled to 492 ft. of salt (NaCL) where a seawater was used to dilute the super-saturated fluid to reduce any washout issue. Another 328 ft. was drilled using a fluid that was a little under-saturated in order to increase Rate of Penetration. Finally, another 164 ft. was drilled still using a super saturated fluid to keep the quality of the cement job and to maintain the hole's integrity. Next, the casings was cemented, then the riser was installed and finally the remaining of the salt and production section were drilled using New Park's synthetic-based drilling fluid.

After the application of this pump and dump technique using the super-saturated salinity drilling fluid, the resulting solution from the case study shows that the condition of the hole was extremely good for and during the running of the casing as well as good casing shoe integrities. In addition, the high saline solution will reduce pitting corrosion in area where the oxygen is present [43], [45].

Table 3.11 Fluid used for the different interval.

Interval (MD)	Hole size [in]	Casing[in]	Fluid used	Volume [bbl]
7,369-7,690	42	36	Seawater	1,364
7,690-10,436	28	22	Seawater	8,840
10,436-10,764			9.0 in /gal NaCl	20,408
10,764-10,213			10.0 ppg NaCl	10,204
Pre cement and cement operations	28		Circulation Hole Clean	4,059
			12.0 in/gal PAD mud	5,100
			Salt mud for cement	2,000

Table 3.12 Components of super saturated drilling fluid. [43]

Components	Purpose
Water	Base Fluid
NaCL	Salinity
Xanthan Polymer	Viscosity /suspension
Caustic Soda	PH Control
Soda Ash	Hardness (Ca^{++}, Mg^{++}) Control
Corrosion Inhibitor	Corrosion inhibitor
Bactericide	Bacterial growth Control

Case 2 – Kymera Hybrid bit

Drilling through deepwater wells with salt formation using conventional drill bit such as *Polycrystalline Diamond Compact* (PDC) bit and traditional *Roller Cone Bit* will face numerous challenges such as:

- Axial, lateral and torsional vibration on drill bit can lead to bit bounce, whirl and stick slip.
- Poor drilling dynamics because of torsional force.
- Drilling through salt formation will typically take two or more bits when using PDC.

Drilling with PDC and roller cone bit through thick salt layer will lead to expensive operation. To improve the drilling performance (higher speed and efficiency) Baker Hughes has developed Kymera drill bit, which is a combination of Roller Cone and PDC. Kymera drill bit reduces vibration and increases the stability, which is suiTable for drilling through the salt formation. Figure 3.18 shows the three types drill bit designs.

Figure 3.88 Different drilling bit. [37]

The cutting mechanism of Kymera bit is both shearing, scraping and crushing. It does the performance of both PDC and Roller cone bit. Kymera drill bit performs effectively in high interns bedded and salt formation. The Kymera field test results in Santos Basin Brazil for pre salt formations have shown that:

- Improves dynamic stability drilling through inter bedded (soft-hard) formations.
- Reduce torque (torsional vibrations) fluctuation than the PDC bit [46].
- Using hybrid bit, ROP increased by 45% and hence reduced operational time by several hours [47].

Case 3: ThermaLock™ Cementing and Salt Shield℠ Cementing

A case study done by Halliburton Company in Indonesia deepwater well and Japan with the use of ThermaLock™ cement to eliminate the cement carbonation [48]. ThermaLock™ cement is a product of Haliburton with the objective of resisting acid and CO_2. These propirties may solve the problem associated with Portland oil well cement. Cement slurry data that used for this case study shown in Table 3.13.

Table 3.13 Cement slurry data for geothermal well in Indonesia and Japan. [48]

	Geothermal Well – Indonesia	**Well – Japan**
Cement slurry	600 bbl.	
Slurry density	14.7 Ib/gal	11.4 Ib/gal
Yield of 2.74 ft^3	73 Ib/sk	
Bottom hole circulating Temperature	110 – 150 °F	210 °F
Bottom hole static Temperature	150 – 300 °F	

ThermaLock proved 100% successful on this project, by reducing concerns about the long-term effect of CO_2 and acid in the wells. Pipe and casing will be protected during operation with high strength development and weight retention. That will save the high remedial operation cost, save the well from abandonment, and re drilling/completion costs as well corrosion issues.

Salt Shield^{SM} Cementing

Salt shield Cement is another slurry product of Halliburton, which can be used in challenging salt zone formation that are located Brazil, West Africa and GOM. It is a combination of unconventional tools such as *Welllife^{R}* service and *Finite Element Analysis* (FEA).

These tools will models the cycle stress of cement sheath that are induced by Temperature and pressure change during life cycle of the well. This tools dealing with planning along with advanced cement slurry system, that are formulated as resistant to CO_2 and resistant to chemicals.The following Table shows the comparisons between the *salt Shield*.^{SM} and Salt *ThermaLock^{SM} are* summarized in Table 3.14

Table 3.14 Advantages and disadvantages of both cement design. [48] , [49]

ThermaLock^{SM} Cementing	Salt Shield^{SM} Cementing
Reduce CO_2 effects in the long term as well as the acid in the well.	Reduce gelation of the cement slurry.
Reduces costs relating to remedy operations.	Stand against loads caused by the plastic behaviour of salt.
Cost saving in respect to avoiding abandonment, re-drilling and completion operations.	Prevent the probability of wash out and weakening of the formation caused by dissolution from the salt formation.
Does not need special cementing equipment or techniques.	High compressive strength with low permeability.
SuiTable for various Temperature profile.	High Corrosion resistance caused by carbon dioxide and no HSE issues.

3.3 Production Phase

Once a well has been drilled to reach the reservoir, then the well is ready for production. This is done by installing production tubing along with its accessories such as production packer and lower completion equipment to control reservoir flow and solid control. However, during the life of the well, the thermodynamic stats in the well and the reservoir changes. That is pressure reduction and also Temperature reducing during the shut-in period in the well. These changes result in petroleum chemistry related problems such as the formation of wax and hydrate. The problems cause flow line blockage. This section will discusses the challenges and the solution of these two selected problems. Off course, asphaltene, scaling, and sand production is also part of flow assurance issues. However, due to the research time limitations are not described. Later, corrosion issue will be presented.

3.3.1 Gas Hydrate

Gas hydrate is a mixture of water, and natural gas resembles (such as ice or blush) caused by the blockage in tubing and pipeline. Hydrates are formed at low Temperatures and high pressures in the presence of water and gas. Figure 3.19 illustrates the formation of hydrate as water mixed with methane gas as appropriate hydrate formation pressure and Temperature. In addition, the gas caged in the water molecule. Figure 3.20 shows the photographed picture of hydrate plugging flow line. For Deepwater wells, the risk for gas hydrate formation always exists due to the low seabed Temperature

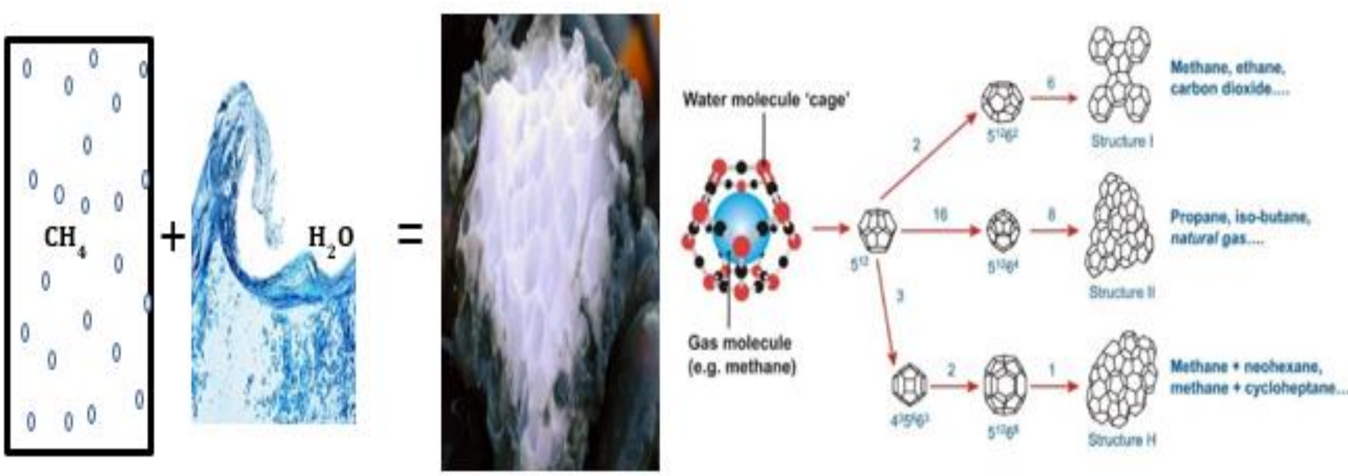


Figure 3.19 Illustration of hydrate formation and types of hydrate crystals. [76]

and the coexistence of gas and water inside the wellbore. If a kick takes place, gas hydrates can form in the blowout preventer (BOP) or choke-line while the kick is circulated out [50].

Figure 3.20 Photography picture of hydrate plugging flow line. [51]

Figure 3.21 illustrates the hydrate stability in a geological formation. Drilling through these formations causes a release of hydrocarbon, which will reduce the well pressure. In addition, it may be hazardous for creating a minor kick condition. As the water depth increases the thickness of hydrate (in yellow shaded) will also increases. Drilling in the top section of the deepwater environments in hydrate formation is challenging since it results in wellbore enlargement and the release of gas, which reduces the well pressure [6].

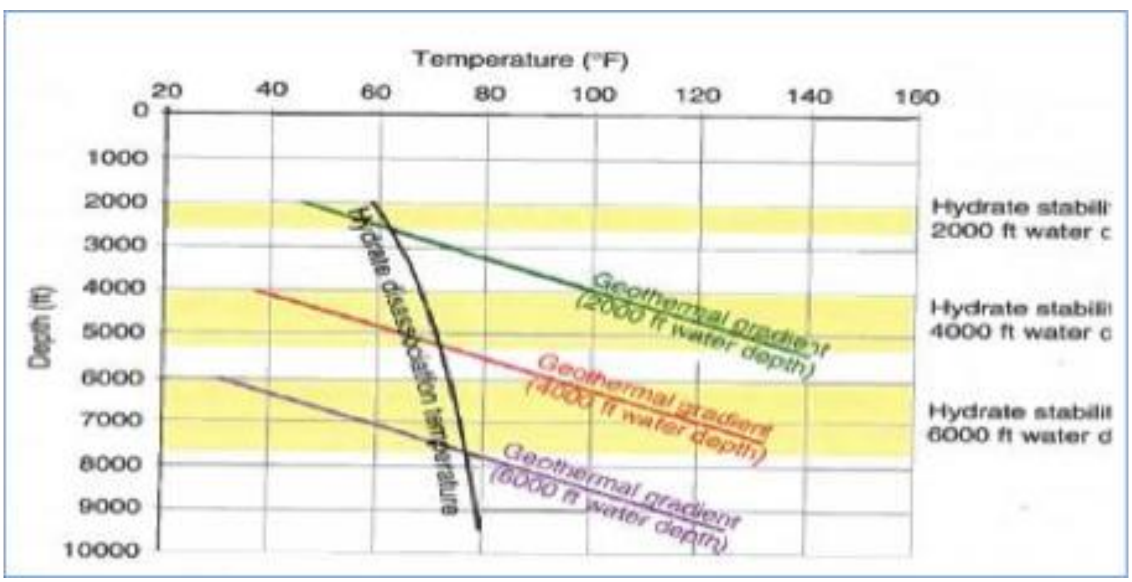


Figure 3.21 Hydrate stability in deepwater and permafrost. [6]

Seismically, the Bottom Simulated Reflector (BSR), as shown in Figure 3.22, which is the most common indication for a hydrate zone in offshore, can identify the hydrate section indirectly. BSR marks the boundary between the sTable hydrate zone and free gas zone beneath. The seismic data records zone by changing both the acoustic velocity and density, since both the density and the seismic velocity of the free gas is much lower than that of hydrates. The boundaries between the zones give a strong reflection in the seismic data [51].

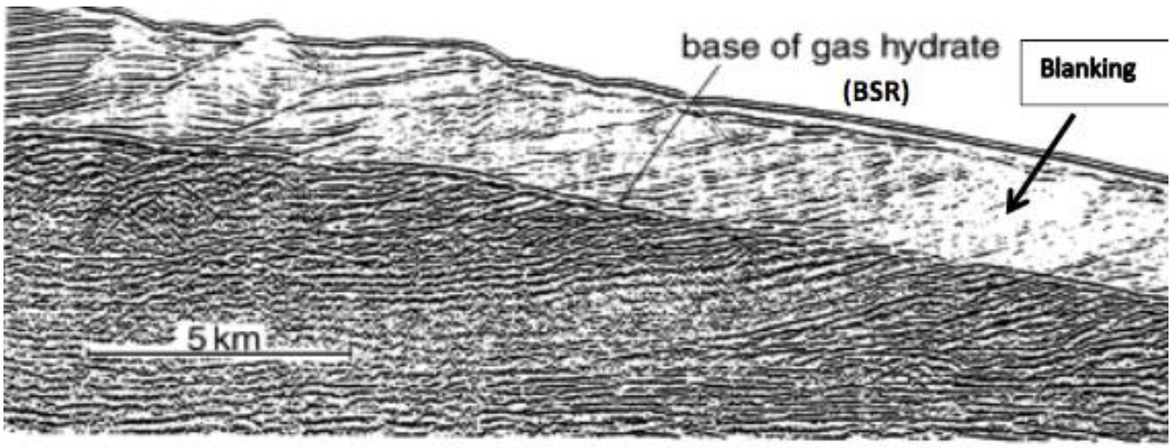


Figure 3.22 Seismic profile from Blake Ridge, showing BSR and blacking. [51]

3.3.1.1 *Gas Hydrate Inhibitors*

Thermodynamic inhibitors work by shifting the hydrate formation curve towards lower Temperature and higher pressure. This creates an increased hydrate free Temperature range during operations. The most commonly used hydrate inhibitors are alcohol and glycol. These chemicals work by decreasing the activity of water. Water forms hydrogen bonds with alcohols and glycols or strong bonds with salt ions. These bonds compete with water hydrate bonds and prevent hydrate formation until much lower Temperatures are reached [6].

Salts are also used as thermodynamic hydrate inhibitor. Some examples are Natrium Chloride ($NaCl_2$), Calcium Chloride ($CaCl_2$) and Potassium Format (HCOOK). These salts are often used in drilling fluids to suppress hydrate formation. This method will lead to modifying the equilibrium curve for hydrate at lower Temperatures or higher pressures. Figure 3.23 shows the performance of the single and combined effect of thermodynamic inhibitors. As shown, the effect of salt and Methanol (Me OH) shift the stability curve more than the others.

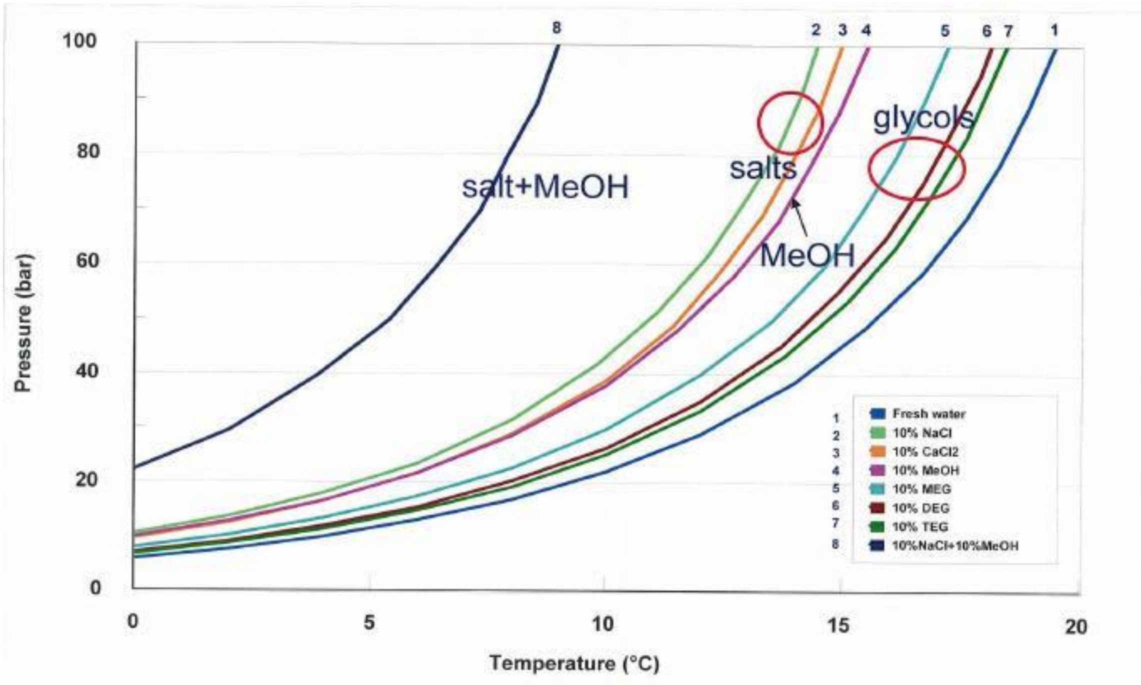


Figure 3.23 Hydrate curves with 10 % wt. inhibitors for gas -condensate system [51]

3.3.1.2 Cold Flow

In cold flow operation, hydrates are crystallized in a chemically conditioned fluid to form a stable slurry mixture. The slurry substance create hydrate crystals throughout the liquid phase so that hydrates can flow in suspension along the pipeline. Cold flow technology reduces hydrate agglomeration in flowing systems but it does not prevent hydrate nucleation. In fact, hydrates are allowed to form, but they form in such a way that they become inert so that they do not agglomerate. Cold Flow technology can eliminate any requirements for bulk and speciality chemicals during normal steady state operations in both gas and oil production streams [6].

Case Study – DST Gas Hydrate Prevention

This thesis uses methanol as gas hydrate inhibitor to illustrate the *Drill Stem Test* (DST) design for deepwater wells. The hypothetical data used for a case study in a deepwater gas well are given in the Table 3.15 [52].

Table 3.15 Key parameters for deepwater gas well. [52]

Gas zone depth	10 000 ft.
Reservoir Temperature	170 °F
Reservoir pressure	4 800 psi
Estimated permeability	300 MD
Water depth	4 000 ft.
Sea level Temperature	70 °F
Sea bed Temperature	40 °F
Gas rate	0 – 35 MMcf/d
Gas S.G (air = 1.0)	0.7
Condensate S.G. (water = 1.0)	0.756
Water content in natural gas	Water saturated gas

Case A – 30 MMcf/d:

In this case, the flow is carrying enough heat from the reservoir. No gas hydrate will form see figure 3.24.

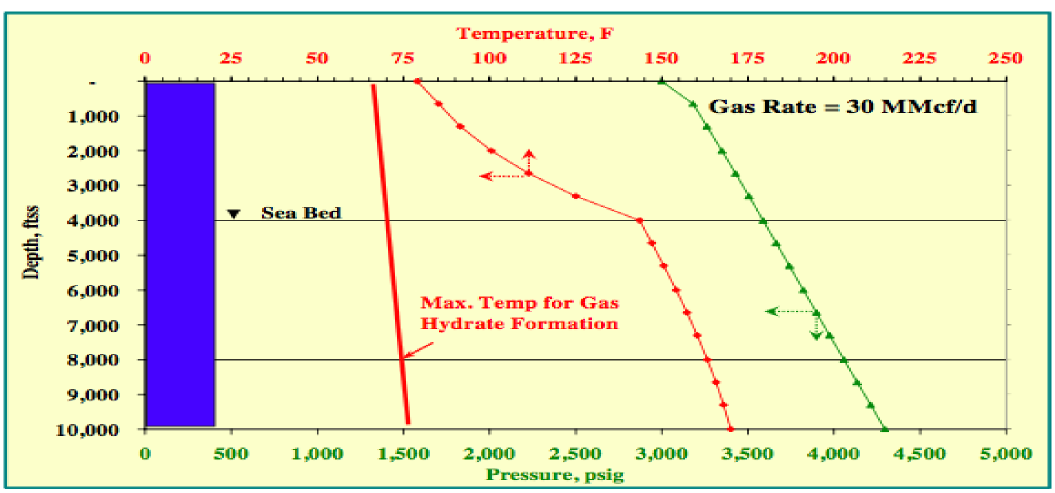


Figure 3.294 Wellbore Temperature and pressure profile -30 MMcf/d [52].

Case B – 15 MMcf/d

In this case figure 3.25, the flow is not carrying enough heat from the reservoir to keep the upper part of the wellbore above the gas hydrate region. Gas hydrate will form if both gas and water exist in the wellbore.

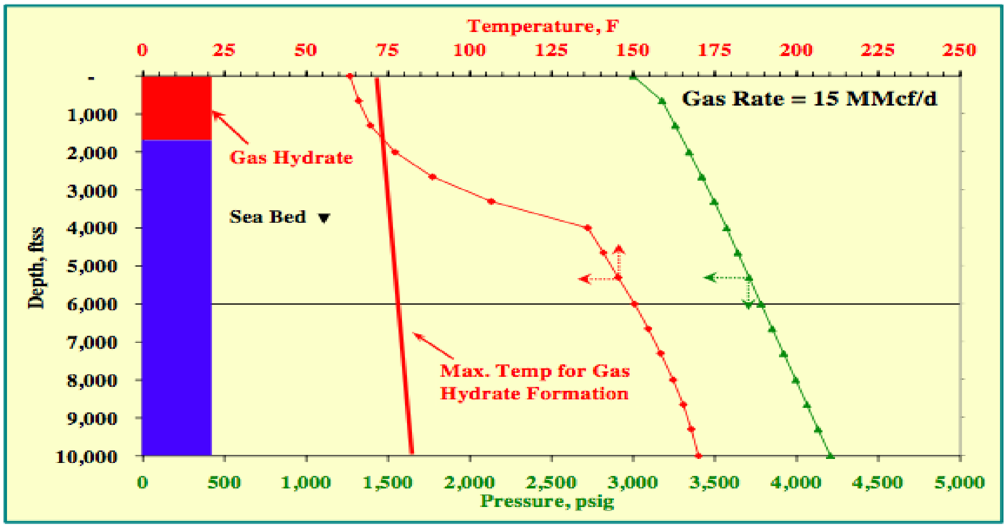


Figure 3.25 Wellbore Temperature profile and pressure -15 MMcf/d [52].

Case C – 0 MMcf/d

Case C is a shut-in case figure 3.26. After shutting the well, the Temperature inside the wellbore will decline with time and eventually equalize with the surrounding Temperatures. Once hydrate forms, it may extend to over 5 500 ft. of gas hydrate column if there is sufficient water in the wellbore.

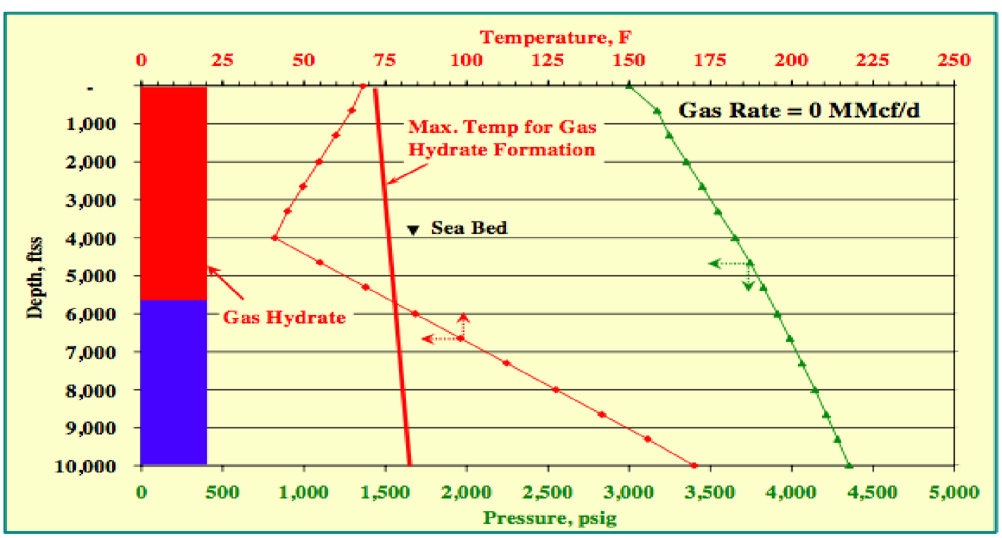


Figure 3.106 Wellbore Temperature and pressure profiles-0MMcf/d [52]

Based on the aforementioned section discussions, the hydrate related challenge and solution are summarized as follows:

3.3.1.3 Challenges

Temperature and pressure is a requirement for gas hydrate formation. The mixture of water with gas forms hydrate in flow lines and in a geological formation. If hydrate formation is not controlled some consequences that can arise are:

- Choke- and Kill-line plugging which prevents their performance in well circulation.
- Plug formation between the drill-string and the BOP will prevent full BOP closure.
- Plug formation in the ram cavity of a closed BOP will prevent the BOP from fully opening properly.
- The formation of gas hydrates increases none productive time and risk that will be costly.
- Plug formation around the drill string in the riser, BOP, or casing will prevent drill-string movement and proper operations performance.
- Plug formation at or below the BOP will prevent well pressure monitoring [6], [53].

3.3.1.4 Solution

The current technology and methods to manage and prevent hydrate nucleation, the solutions are summarized as:

- Avoid operating at the Temperatures and pressures which are favourable to their formation
- Use of gas hydrate inhibitors, these may be thermodynamic inhibitors or kinetic inhibitors
- Cold inhibitor by maintaining the wellbore Temperature
- Removal of water and wet gas from the system.

3.3.2 Wax

A common occurrence in development and maintenance of oil operations is wax deposition in production pipelines, creating flow assurance risk. The major issues right to wave precipitation are its deposition during flowing state and gelation while in shutdown conditions. Wax is deposited when by precipitation and deposition of the paraffinic components on the cold pipeline wall as it falls below the cloud point Temperature. If the problem is not resolved and the prevention methods fail, the wax layer increases its thickness and leads to oil-flow slow down. As shown in figure 3.27 Stock tank oil Wax Appearance Temperature (WAT) is used as a design criterion in protection from wax precipitation in multiphase in field flow lines [54].

For a wax deposition to happen in a pipeline, the two conditions below must be met:

- The oil Temperature by the pipe wall must fall below the wax appearance Temperature:

$$(T_{oil} < WAT)$$

- The wall Temperature is lower than the oil Temperature:

$$(T_{well} < T_{oil})$$

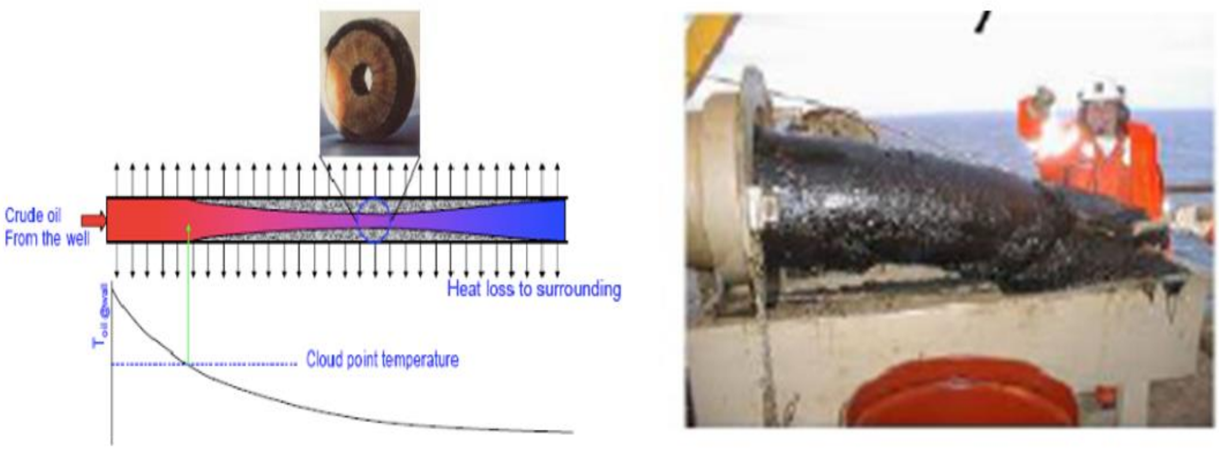


Figure 3.27 Wax deposition when inner wall Temperature is below could point Temperature. [51], [55]

3.3.2.1 Challenges

As previously discussed, flow assurance is the primary obstacle created by wax precipitation. This becomes more apparent during the production and pipeline transportation halt due to a planned maintenance or emergencies. Such as difficult weather conditions in the concerned offshore platforms. This leads to significant decrease in the Temperature and solubility of the was hence leads to wax molecules precipitation out of liquid phase in a state condition.

- Wax built up leads to blockage and restriction in flow rate out of the well.
- The rheology of the crude oil can be modified from Newtonian to non-Newtonian flow characteristic.
- Restarting the flow leads to high-yield stress.
- High stress used to break the gel and resuming the flow can be harmful to the pumps and pipelines.
- High cost incurred due to wax deposition management leads to increase in both capital and operation costs [55].

3.3.2.2 Solutions

To prevent wax deposition, it is advised that the system is designed in a way that keeps the minimum flow Temperature above WAT. Paraffin wax treatment that is divided into two main categories, mitigation of the deposition and removal of the paraffin wax deposits [55]:

- ***Mitigation Techniques:***

Mitigation of deposition can be done in three ways: Cold Flow, Wax Deposition Reducing Chemicals and Application of Different Pipe Materials and Pipe Coating.

- ***Cold Flow Process:***

Figure 3.28 formation of solid Slurry at the first section of the pipe can be stably transported without further solid deposition. Oil exit of the process is at the same Temperature as the external environment hence all the probably wax have been precipitated. The solid slurries are created via a number of methods, such as:

- Cold seeding
- The wax eater
- High-shear
- Heat exchanger
- Pressure surges
- Flash cooling
- Oil or solvent injection
- Magnetic conditioning

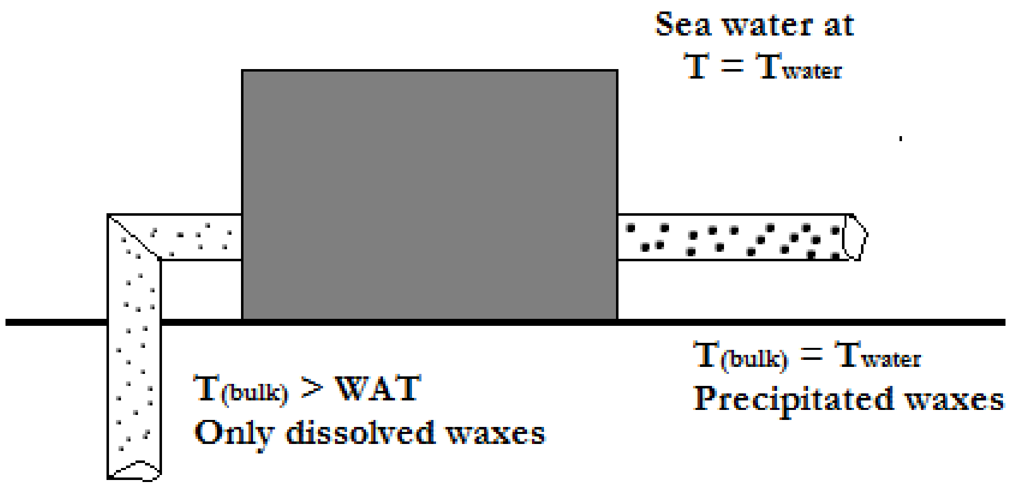


Figure 3.118 Cold flow process. [55]

- ***Wax Deposition Reducing Chemicals:***

To reduce and mitigate the paraffin wax deposition some chemicals are used, such as Crystal Modifiers, Deposition Inhibitor, Surfactants and Polymer Additives. The wax crystal modifiers incorporate themselves with the growing wax.

- ***Application of Different Pipe Materials and Pipe Coating**:*

Since the paraffin deposition on plastic pipes is slower than it is on steel, it is suggested plastic use pipe or plastic coated pipes to reduce wax deposition.

- ***Removal Technique***:

Removal technique is divided into four major parts: *Fused Chemical Reaction, Mechanical Removal, Heat Application*, *Wax Removing Chemicals*, and Use of *Microbial Products*.

- ***Fused Chemical Reaction:***

Is to use fused chemical reaction along with controlled heat emission in order to remove wax deposits from the pipes.

- ***Mechanical Removal:***

In this method, which is also known as pigging, a pig passes through the pipe removing the wax deposits as shown in figure 3.29, this method can not be efficiently implemented without a proper prediction for the wax deposition.

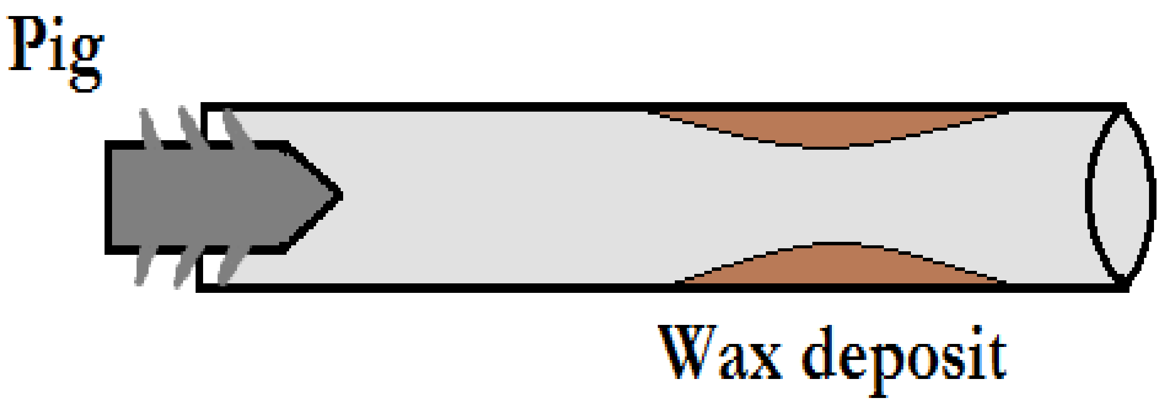


Figure 3.29 Pigging method. [55]

- ***Heat Application:***

The heat is applied via various methods such as injecting hot oil, hot water or steam and electrical pipe heating. This solution is most effective when applied at early stages before the accumulation of larger paraffin deposits in the production equipment [55].

3.4 Plug and Abandonment phase (P&A)

Plugging and Abandonment of the well can be a time-consuming and costly operation with no rewards. There are several challenges associated with P&A operation. The recommended operational P&A standards and regulation varies from country to country. For instance, NORSOK D-10 is applicable for *Norwegian Continental Shelf* (NCS) and similarly, GOM has its own regulations. The degree of challenges varies from place to place. This thesis presents some of the challenges and current technology to resolve the problems along with future technologies under development phase to improve the P&A operation.

3.4.1 Challenges

Technical and operational challenges related to P&A operation among others are:

1) Rig Capacity

During P&A operations usually, *Mobile Drilling Units* (MODU) such as FPSO and semi submersibles are used to perform the required operations such as well integrity, zonal isolation, pumping of cement, retrieval of tubing and casing followed by section milling. These types of operations results in high daily rate of (MODU), in addition to NPT caused by operational failure. High cost of mobile installation will be quite expensive for P&A operations. Normally an alternatively method which are less expensive used to handle lightweight well intervention operation which are *Riser Less Well Intervention* (RLWI) vessels. This ship shaped vessels are limited to water depth reaching 3 280 ft. [56].

2) Tubing Corrosion and removing of Production tubing

Deepwater drilling requires several numbers of casing strings with smaller diameters. During P&A operations those casing string should be removed before plugging and cementing the well. In order to remove the casing string from the well certain number of trip are required. Starting from retrieving the casing hanger and seals from the wellhead, followed by cutting, subsequent pulling the casing, and casing hanger from the well. These processes usually take 8-12 hours of rig time in normal conditions. In case of the tubing is damaged or corrosion got it the daily rate and NPT will increase [56], [57]

3) Section Milling

Due to poor casing-cement integrity, it is a common practice to remove casing by section milling. As shown in figure below, the placing cement in contact with the formation to form permanent barriers. However, the challenges during section milling are the producing of swarfs (see Figure 3.30), which is a difficult operation to remove from the well and are time-consuming [58].

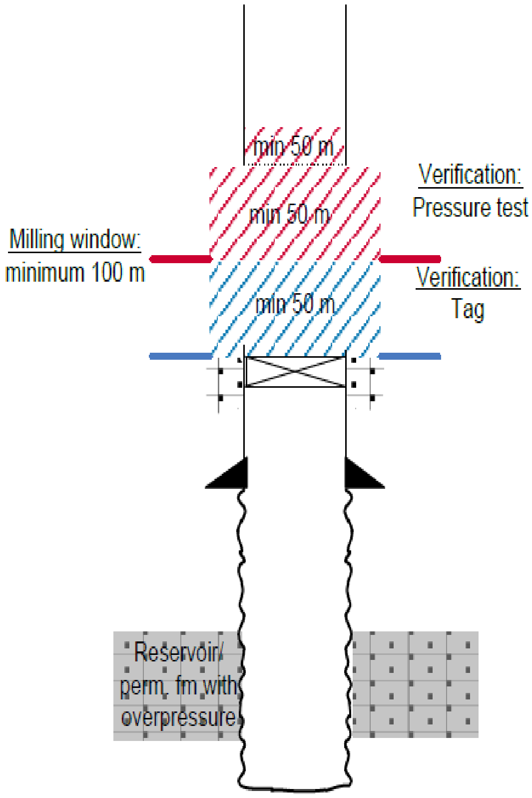


Figure 3.120 Swraf from milling operation. [58]

3.4.2 Solutions

Christopher Halverson [58] has presented field case studies to learn the P&A challenges and solutions. In addition to section milling operation, the author concluded that the installation primary and secondary barrier elements are the most time consuming with the conventional technology. The study is based on the data collected from the shallow depth water offshore wells. The challenges would be more severe as the water depth increases.

Solution #1: Perforate Cement Wash (PCW) Technology

Christer Halverson's [58] field case study has shown that the application of PCW technology is an attractive method to reduce the P & A operational cost significantly. PCW is a single run method, unlike the conventional methods. According to Christer's analysis, installation of primary and secondary barrier element by using PCW technology could potentially reduce the operation time by 73 % as compared to the traditional section milling operation. From this field case study, the author of this thesis believes that PCW could be one of the P&A solution for the deepwater environment. Unfortunately, the author was unable to field case study related to the application of PCW in GOM region.

Solution #2: Hydraulic Activated Tool

Field Case study for a deepwater well (GOM) has shown that hydraulic activated tool, which are launched by Schlumberger to cut 72-inch casing during P&A process. It eliminate the need of multiple trip to remove casing during P&A from the well. It provides better and easier to handle under removal operation of casing string. In addition to reduce cost, NPT and high cost of rig rate, by operate removal issue and get the wellhead seal, assemble at the time. In addition, it will reduce NPT and daily rate caused by multiple trip to remove casing string. The key components of this system are shown in figure 3.31, which include Spear assemble, mud motor, pump sub and hydraulic piper cutter with pressure drop indicator at the rig deck [59].

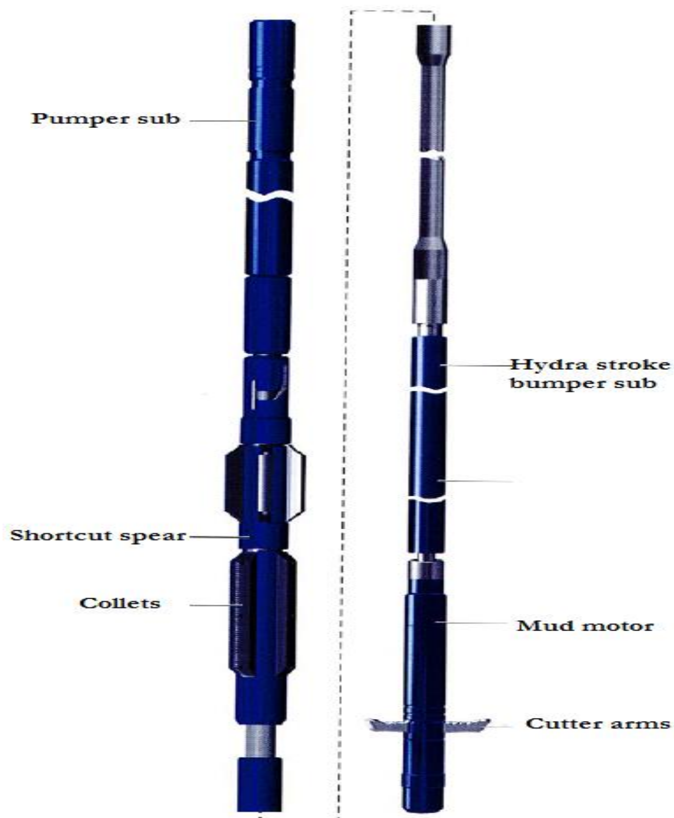


Figure 3.3131 Hydraluic cutter. [59].

Solution #3 Tubing Left in the Well

The conventional P&A operations are normally performed by removing the production tubing. This increase the operational time, which increases cost. One possible way to reduce cost during plugging and abandonment is to leave most of the production tubing in the well, by obtaining good cement placement when the tubing is left in the hole. This will lead to save significant rig time and reduce none productive time as well as cost.

Christer Halverson's research work also documented the tubing left in the well, which significantly reduces rig time during P&A operations. Figure 3.32 illustrates the process of plug installing while leaving the production tubing in a well. During P&A operation, tubing should be cut at the top of production packer. Then lifted in order to get access to the producing casing in order to log the casing-cement integrity with *Cement Bond Log* (CBL) and *Ultra Sonic Imager Tool* (USIT) tools. Once the log responses show good cement/formation/casing bond, cement is pumped through the tubing. Finally, the tubing is landed on the cement plug.

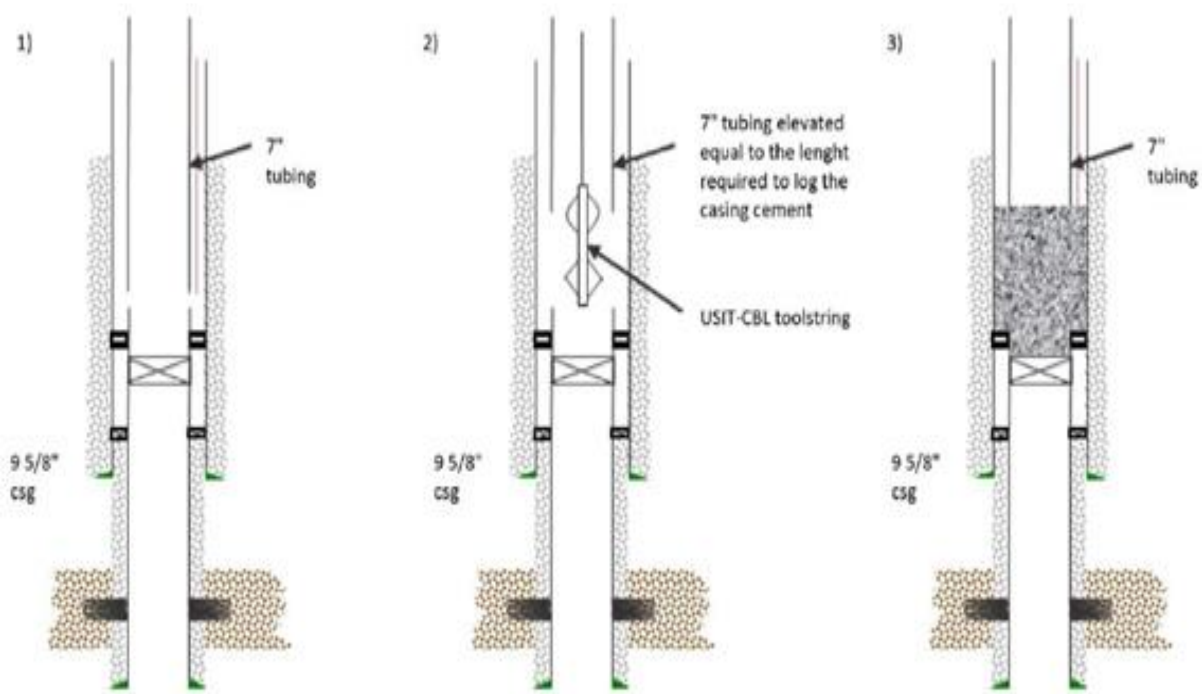


Figure 3.3142 Tubing as work string to place cement. [58]

For the Heimdal field in the North Sea, Statoil has implemented the aforementioned methods in results in a reduction of operation time. As Figure 3.33 displays, the percentage of saving of the total P&A operational time per well ranges from 8% to 18%. The overall average time saving was found to be 12.8 %. It also needs to be noted that the method reduces the tubing handling time at the deck, and disposal and logistic problems as well

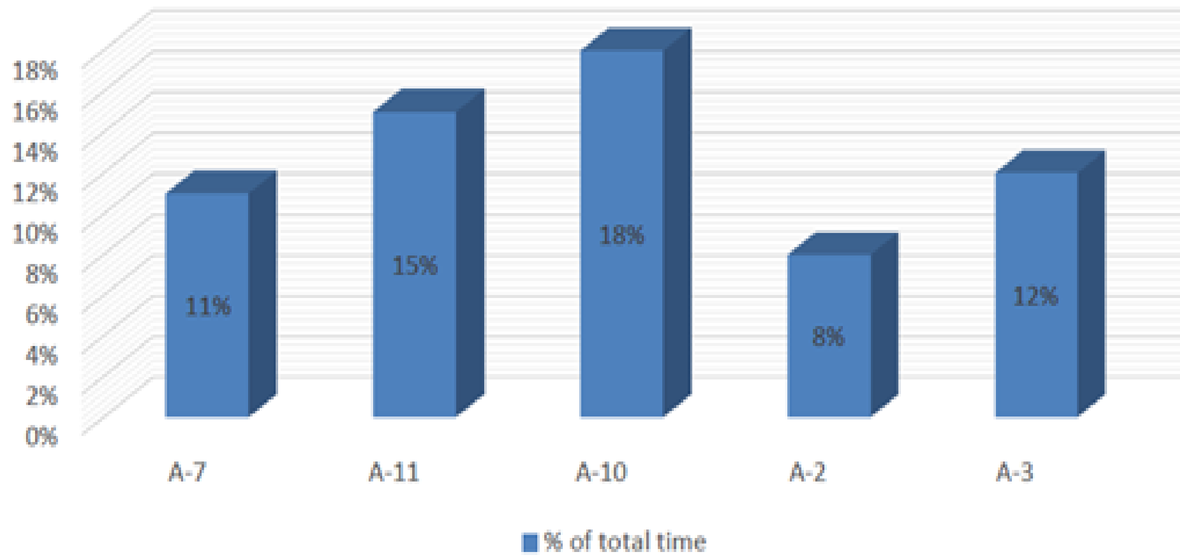
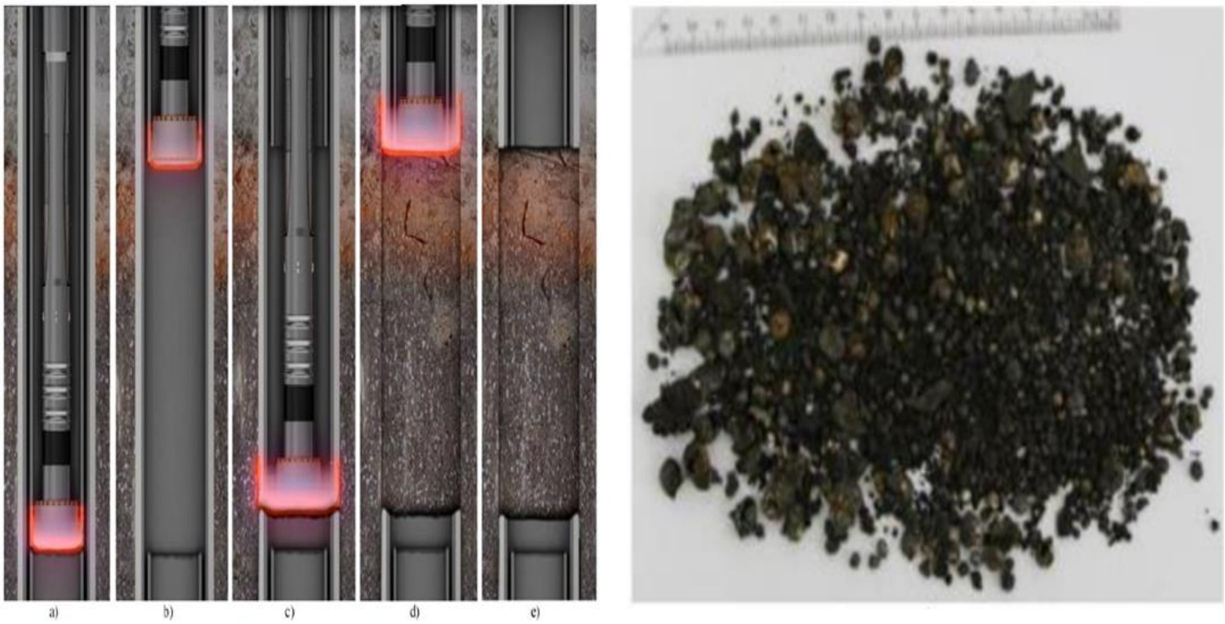


Figure 3.33 P&A total time saving per well in % - TTBP on Heimdal. [58]

Solutions #4: Other Future Technologies under Research and Development

Cutting technology such as plasma bit milling technology [60], Upward/Reverse section milling [61] are documented as future technologies for efficient and cost effective P&A operation. These are under research and development phases. Cement technology documented in reference is under research and development phase. The test results show a reduced leakage due to the cement expandability property.

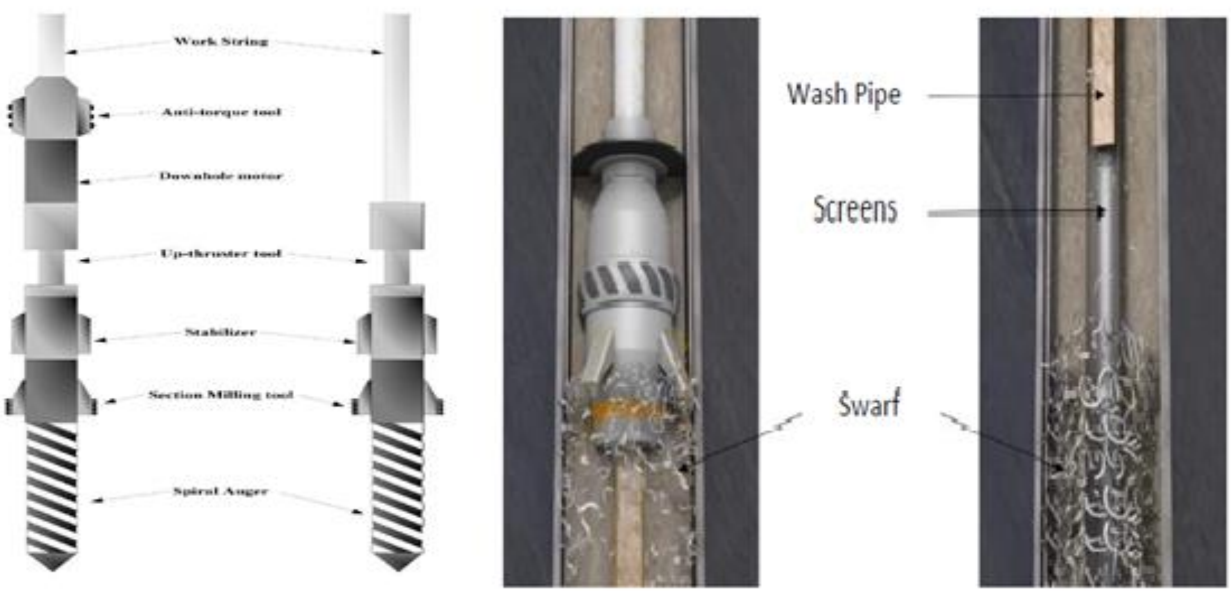
Figure 3.34a illustrates the cutting process of plasma-based tool. As shown, the tool is connected and run with tubing. The electric arc ignition creates plasma as shown in the figure. Once part of the casing /cement removed, the tool will be pulled out of the well for further cement plug job. Figure 3.34b shows the approximate 5mm cutting resulting from the plasma milling.



a) Section milling b) Cutting size

Figure 3.34 (a) Illustration of section milling with plasma (b) Cutting size from plasma milling technology. (59)

Figure 3.35 displays the upward section milling tool and figure by the milling action of by the Sward Park tool, which is the reverse action. As shown in the figure, as the SwarfPak milling upward.The generated swarfs are deposited in the downhole rather than being transported up as the traditional method.



a) Tool assembly **b)SwarfPak tool**

Figure 3.35 Reverse section milling. (57)

3.5 Corrosion

Metals can be corroded as they are exposed to corrosive environments. This as a result, deteriorates the material property. Since drilling equipment are made of steel, corrosion is common in the oil and gas wells. This leads to both economy loses and HSE issues. In fact, corrosion problems occur at any phases of petroleum operations. In addition, problems also occur in our daily life and in any industry. Figure 3.36 shows a nationwide corrosion related case study from the US indicates that the cost of corrosion obtained from five sectors is about \$ 276 billion per year. Among these, the oil and gas industry share is \$ 1.372 billion. As shown in Figure 3.37, the highest cost of corrosion in the oil and gas industry is due to chemical treatment [62].

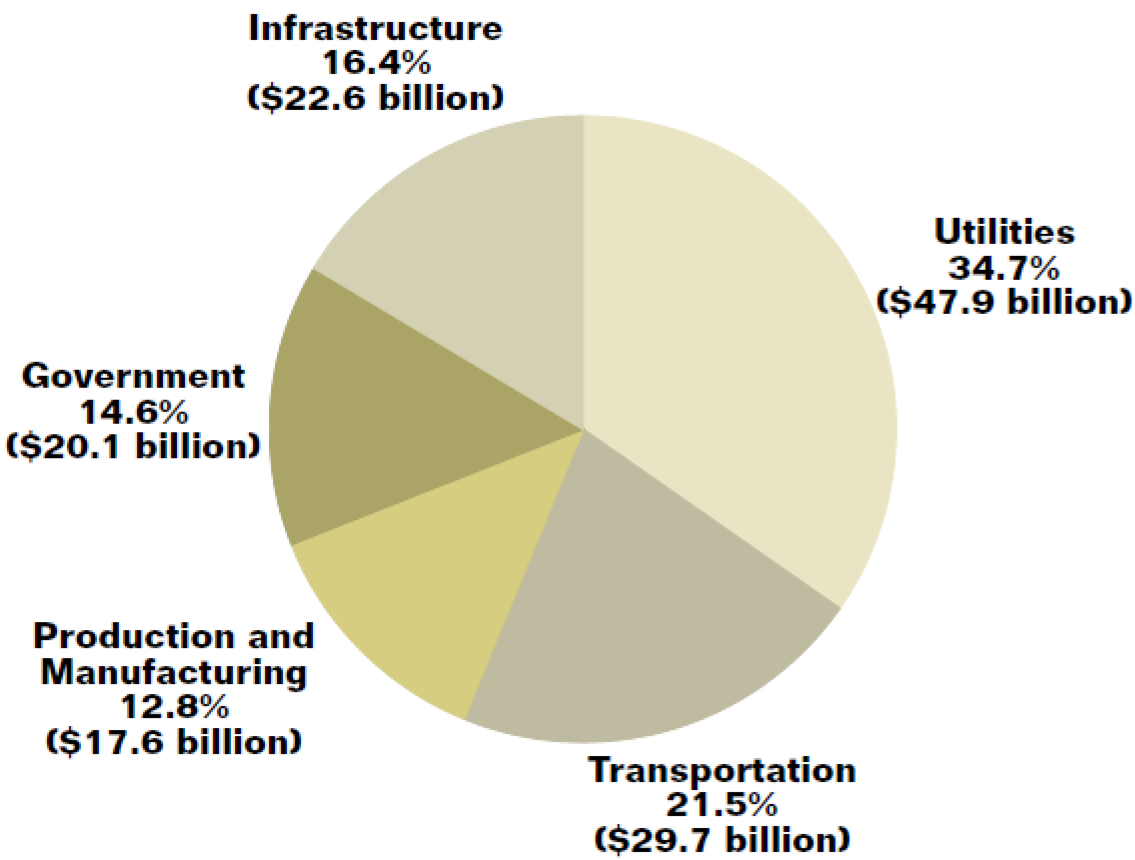


Figure 3.36 Nationwide corrosion problems in five sectors in the US. [62]

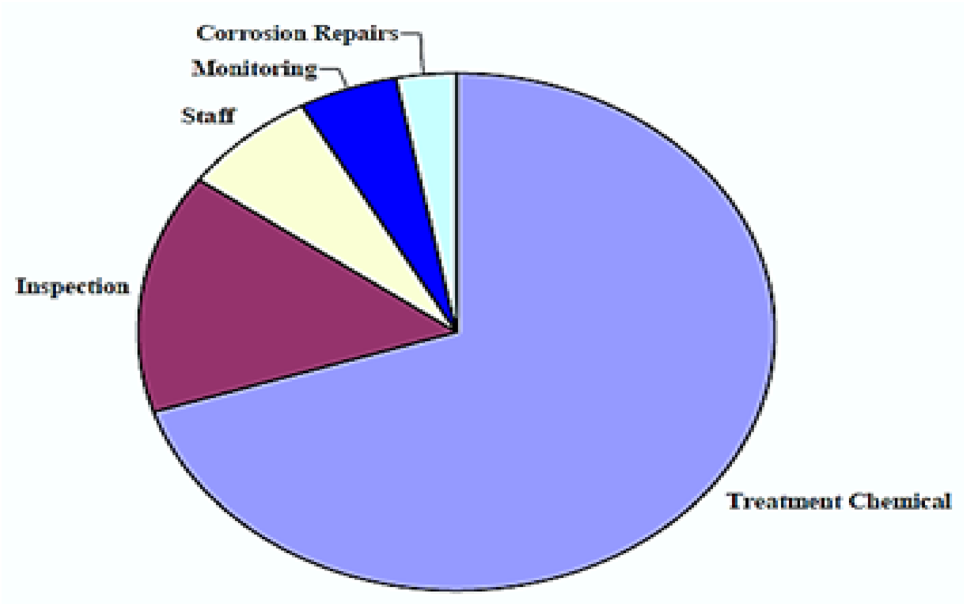


Figure 3.157 Corrosion cost in Oil and Gas sector. [51]

3.5.1 Corrosive gases

The most common corrosive environments in the oil and gas industry are O_2, CO_2, and H_2S.

In addition, microbial activity may cause corrosion. As shown in Figure 3.38, the corrosion rates of carbon steel due to O_2 higher than CO_2, and H_2S. During operational phases, it is important to

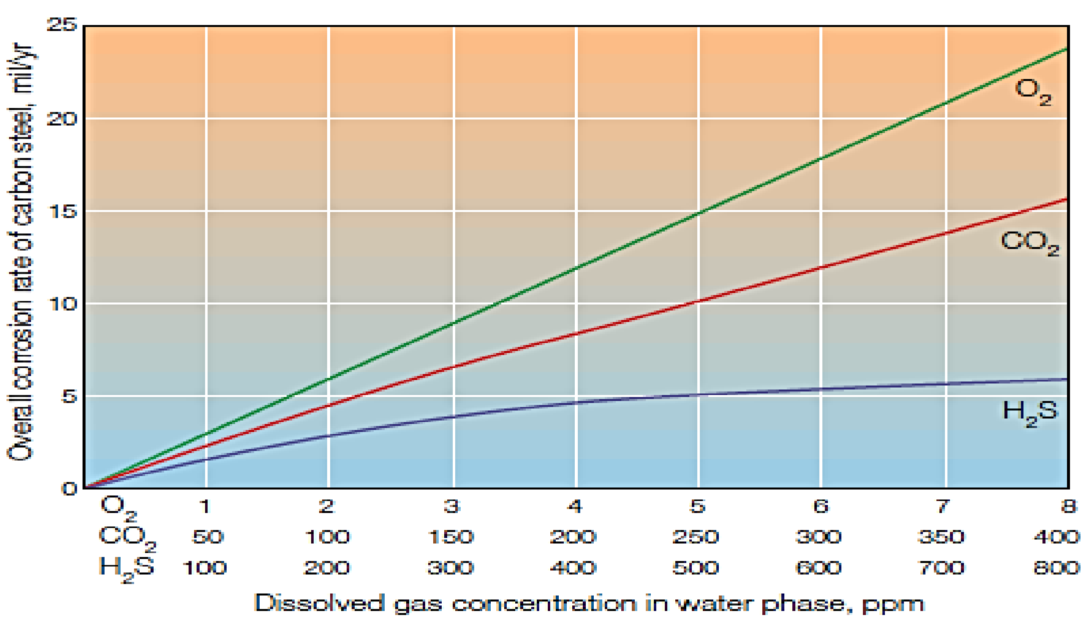


Figure 3.38 Dissolved gas concentration in water phases, ppm. [63]

monitor and detect the nature of corrosion. Based on the type and the degree of severity, a remedial action should be taken in order to slow down the corrosion rate. In the worst-case scenario, material replacement is a better solution. To design system and select material based on the knowledge of the environment, the loading and operational condition [63].

Following recommended practices and standards are key for material selection for a long and productive wells life.

3.5.2 Challenges Caused by Corrosion and their Solutions

Challenges caused by corrosion and various proven solution are summarized in Table 3.16. Proven methods for preventing and controlling corrosion depend on the specific material, environmental concerns such as soil resistivity, humidity, and exposure to salt water or industrial environments, and many other factors. The most commonly used include organic and metallic protective coatings.

Table 3.16 Challenges caused by corrosion and their solutions.

Challenges	• Decrease of metal thickness, which causes failure of structure, or break down and generate loss of mechanical strength. • Pumps, valves, and pipes that are blocks by corrosion build-up leads to mechanical damage or failure. • Corrosion build-up decreases heat transfer rate in heat exchangers • Structural failures and destruction can create hazardous situations and possible injuries to people.
Solutions	• Usage of corrosion inhibitors to prevent corrosion or to slow down the already present corrosion process. • Application of organic and metallic protective coating, such as plastic liners, cement liners, and corrosion resistant alloys. • Removal of corrosive gases. • Application of cathodic protection, this is where the protected material surface are turned into a cathode of a corrosion cell due to the fact that corrosion happens at the anodes.

	• Mixing inhibitors, which works to inhibit anode and cathode reaction for example using Benzotriazole for copper alloy protection. • Usage of coating layers to act as a barrier in order to prevent the surface from coming in contact with the corrosive agents. Coating layers that are used are paint, coating lining, metallic sheets, fibreglass epoxy, rubber, as well as spraying zinc and aluminium on the surface. • Using chemical coating to protect the surface by either merging with the corrosive materials or reacting it with the environment impurities surrounding the metal. • Using one or more of corrosion resistant alloys such as; 13 Cr, Super 13 Cr, 22 Cr, duplex, 25 duplex, and C276 nickel alloy. [6] , [64]

4. Simulation study and analysis

This section present simulation studies to illustrate the effect of pressure, Temperature and conventional drilling methods in narrow operational windows observed in a deepwater environment. The analysis is annular pressure buildup and its consequences, kick tolerance and manage pressure cementing, which is one of the solutions.

4.1 Annular Pressure Build Up and Ballooning

Aadnøy developed a simplified Temperature-induced pressure model, which contribute to the annular pressure buildup. Figure 4.1 shows an illustration of the Temperature profile in an exploration well. The fluid production and transportation in §3.14 theory part a considerable amount of heat is transported via the tubing across the well-constructed section to the formation. Increase in the Temperature results in fluid volume expansion, which subsequently leads to rising of the annulus pressure [9].

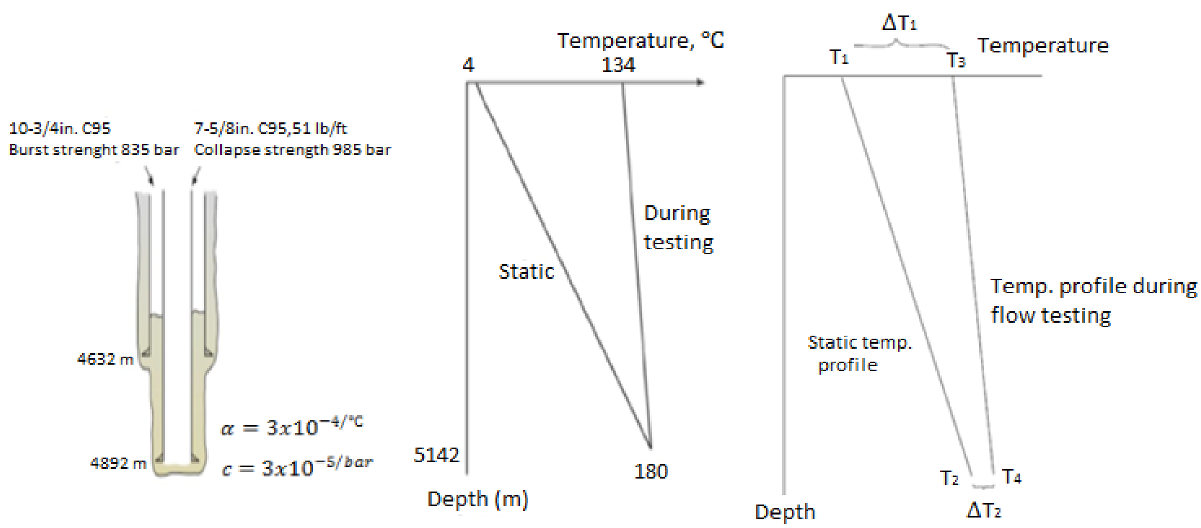


Figure 4.1 Well configuration and Temperature profile. [9]

According to the Temperatures at the wellhead and the bottom, the Temperature-induced pressure is mathematically calculated as [9]:

$$\Delta P = (-\frac{\alpha}{2c})\{(T_3 + T_4) - (T_1 + T_2)\} \tag{28}$$

Where;

ΔP	=	The pressure variation, [psi]
α	=	Heat expansion coefficient, [1/℃]
c	=	Compressibility of fluid, [1/ psi]
T_1, T_2	=	Static Top and Bottom Temperatures, [℃]
T_3, T_4	=	Circulation of Top and Bottom Temperatures, [℃]

4.1.1 Annular Pressure Build Up example

The numerical illustration used for this analysis are given in Table 4.1.

Table 4.1 Numerical example illustration for a Tube.

Burst strength	950bar
Collapse strength	800 bar
Length	20 000 ft.
Inner diameter	7-5/8 inch
Outer diameter	10-5/8 inch
$\boldsymbol{\alpha}$	3, 0 x 10^{-4} 1/℃
c	3, 0 x 10^{-5}, psi^{-1}
$\boldsymbol{T_1}$	4, 0 ℃
$\boldsymbol{T_2}$	180, 0 ℃
$\boldsymbol{T_3}$	134, 0 ℃
$\boldsymbol{T_4}$	180 ℃

$$\Delta P = \left(-\frac{3 \times 10^{-4}}{2 \times 3x10^{-5}}\right)\{(134 + 180) - (4 + 180)\} = 650\, bar \tag{29}$$

In addition, the expected pressure will increase with 650-bar. Compering this result with burst and collapse strength for the casing will be:

Collapse strength	800 bar	>	ΔP	650 bar
Burst strength	950 bar	>	ΔP	650 bar

This means that the design is acceptable because pressure increase for tapped annular pressure build up is less than both casing strength.

4.1.2 Ballooning example

Further, for a stationary tubing the ballooning effect create force change in the tubing is calculated using [6].

$$F_{bal} = -2\mu\ (A_i \Delta P_i - A_o \Delta P_o) \tag{14}$$

Where:

F_{bal}	=	Ballooning effect, [lb.]
ΔP_o	=	Change in average annulus pressure, $[psi]$
ΔP_i	=	Change in average tubing pressure, $[psi]$
μ	=	Poisson ratio
A_o	=	Tubing OD area, $[in^2]$
A_i	=	Tubing ID area, $[in^2]$

Numerical example: Effect of ballooning on tubing force:

The production casing for 7in will be:

μ	=	0.3 Steel
ΔP_o	=	650 bar = 9427.5 psi
A_o	=	38.48 in^2

Where the ballooning force will be:

$$F_{bal} = -2\ x\ 0.3\ (-\ 38.48\ x\ 9427.5) \tag{31}$$

$$F_{bal} = 217662\ Ib$$

The ballooning will create a compressive force on tubing that is 217662 Ib.

During stimulation or gas life operation, tubing may experience ballooning or reverse ballooning as shown in figure 4.2 [6].

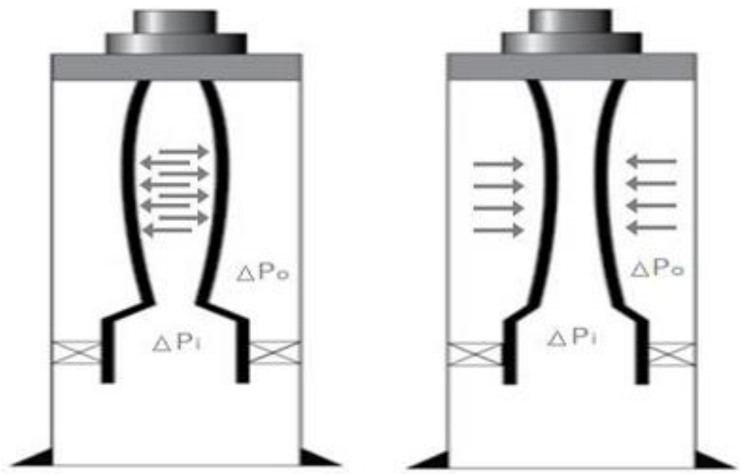


Figure 4.2 Illustration of ballooning and reverse

This result in string compression and elongations respectively, which subsequently leads to change in length due to ballooning or reverse ballooning and this length variation, is calculated by the equation reduced to [6]:

$$\Delta L = -2\mu\ \frac{(-\Delta P_0 r_0^2)L}{(r_i^2 - r_0^2)E} \tag{32}$$

Where;

ΔL	=	Length change due to ballooning, $[in]$
L	=	Length of tubing, $[in]$
E	=	Modulus of elasticity of steel, $[psi]$
P_i	=	Pressure in tubing, $[psi]$
P_0	=	Pressure in annulus, $[psi]$
r_i	=	Inner radius, $[in]$
r_0	=	Outer radius, $[in]$

Assumptions;

L = 20 000 ft. = 240 000 in

E = 30 x 10^6psi for steel

$$\Delta L = -2\ x\ 0.3\ x\ \frac{-\ 9427.5\ \text{psi x}\ (6.538^2)\times 240\ 000\ \text{in}}{(7^2 - 6.538^2)\times 30\ \text{x}\ 10^6} = 355.3\ in\ (9\text{m}) \tag{33}$$

The exerted pressure within the annulus squeezes the tubing and create reverse ballooning effect and leading to the elongation of the tube. As illustrated in figure 4.3: the inner diameter increases from 5.05 in into 6.538 in, the 7" OD casing elongated from 2.4 m to 9 m respectively.

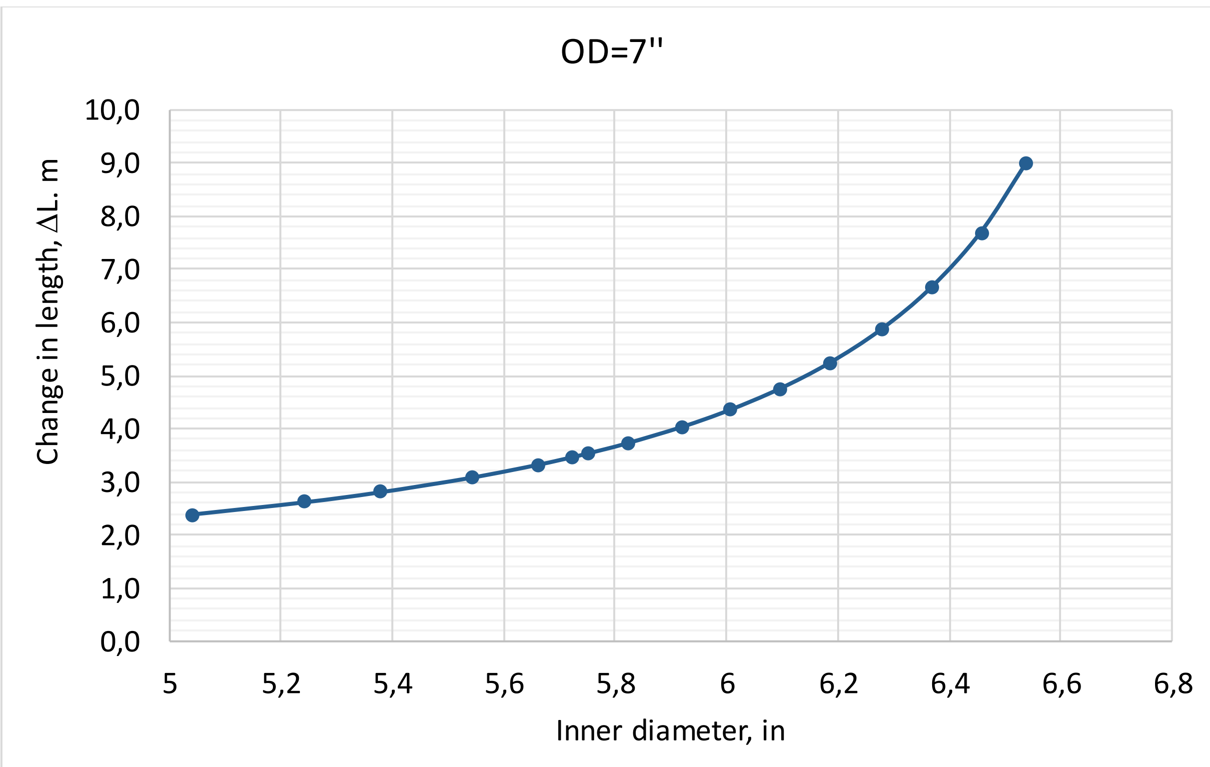


Figure 4.3: Simulated 7" in casing elongation for various inner diameter.

4.2 Kick Tolerance

WellPlan/Landmark ™ simulator has been used to simulate kick tolerance for a vertical well. The casing shoe and the density as a function of kick volume are presented. Driller's method was used to circulate kick out and kill the well. Three different mud densities are used. It has been assumed the weak point fracture pressure at casing shoe (i.e. 20000ft) to be the pressure of 14 805 psi.

Kick Tolerance

Kick Tolerance is defined as the maximum volume of kick received in a well and can be circulated out of the well without out damaging the well at the weak point. This should be determine prior to drilling operation.

Casing shoe pressure

The pressure at the casing shoe is the weakest point. This can be determined from Eq. 36 as [65]:

$$P_{CS} = BHP - (\rho_{mix}\ x\ 0.098\ x\ h_{tvdcs}) \tag{15}$$

Where:

P_{CS}	=	Pressure at casing shoe, $[psi]$
BHP	=	Bottom hole pressure, $[ppg]$
ρ_{mix}	=	Active mud density with influx, $[ppg]$
h_{tvdcs}	=	Depth difference through vertical depth at current shoe, $[ft.]$

BHP is calculated as following;

$$BHP = \rho_{mud} \times 0.052 \times h_{tvd} \tag{34}$$

Where;

ρ_{mud}	=	Active mud density, $[ppg]$
h_{tvd}	=	True vertical depth where influx is assumed, [ft.]

4.2.1 Simulation arrangement

A total of the 30,000ft vertical well has been considered for the simulation, where the seabed/water depth was at 5500ft. The 13”x12” drilling riser has been installed in 8.5 ppg seawater. The 15000ft part of the well has been cased and 10000ft of the well is assumed an open hole. Figure 5.3 illustrates the well structure designed in Well plan simulator. Table 4.2 - 4.5 show the details of the well geometry and the string data used for the simulation well.

Table 4.2 Well Geometry

Hole section	**Size [in]**		**Start Depth [ft.]**
	OD	ID	-
Riser	13,0”	12,0”	0
Casing	9,625”	9,002”	5000
Open hole	-	8.5”	20000

Table 4.3 Drill string data

Bit OD	8,500”
Length of bit	1,00 ft.
Drill pipe OD	5,00”
Drill pipe ID	4,276”
Length of drill pipe	299999 ft.

Table 4.4 Geothermal gradient

Initial mud gradient	0,597 psi/ft.
Circulation flow rate	250 gpm.
Kick interval gradient	0,101 psi/ft.
Influx type	Gas
Kill rate	250 gpm.
Depth of interest	20000 ft.

Table 4.5 Dial reading

Speed (RPM)	Dial Reading (°)
600	92
300	58
200	46
100	32
6	10
3	8

4.2.2 Result

Figure 4.4 shows the influx (in blue) volume movement from where the influx is taken (i.e. at the bottom) until it is located at casing shoe. The yellow part in the figures is an old drilling fluid, which caused kick and the blue at the bottom is as kick received and at casing shoe during migration kill process. The casing shoe pressure is the weakest point pressure (i.e. 14 805psi) where the kick tolerance analysis is performed with respect to this pressure.

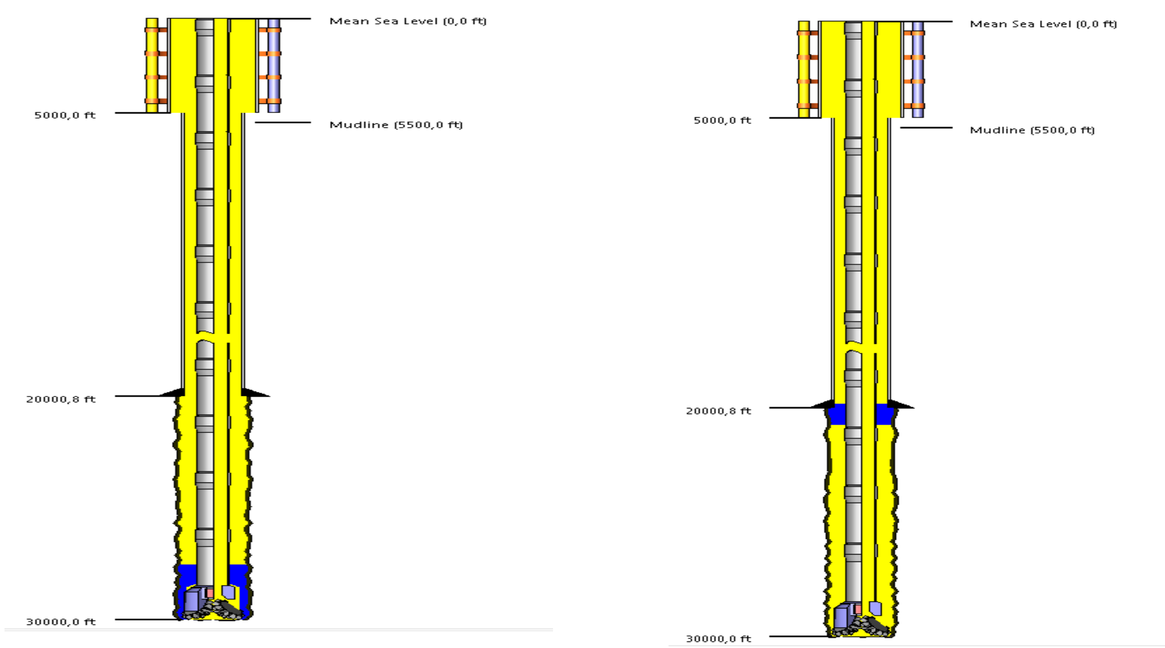


Figure 4.4 Well schematic with influx of kick.

As shown in figure 4.5 the volume of kick behaves as the influx of kick is circulated out of the well with Drillers method, for different mud density with a fixed influx volume. As expected pressure at casing shoe increases with increasing volume of influx or lower mud density. With the increase in influx and/or high density of active mud, the pressure of the casing shoe increase. For better presentation, Figure 4.6 displays the kick tolerance of the well as the mud density varies from 11.5 ppg, 12.0 ppg and 13.0 ppg the figure is generated from Figure 4.4. The maximum kick that can be circulated out from the well without fracturing the weak formation at casing shoe. The lower the mud density the more volume of kick can be taken out without fracturing the well.

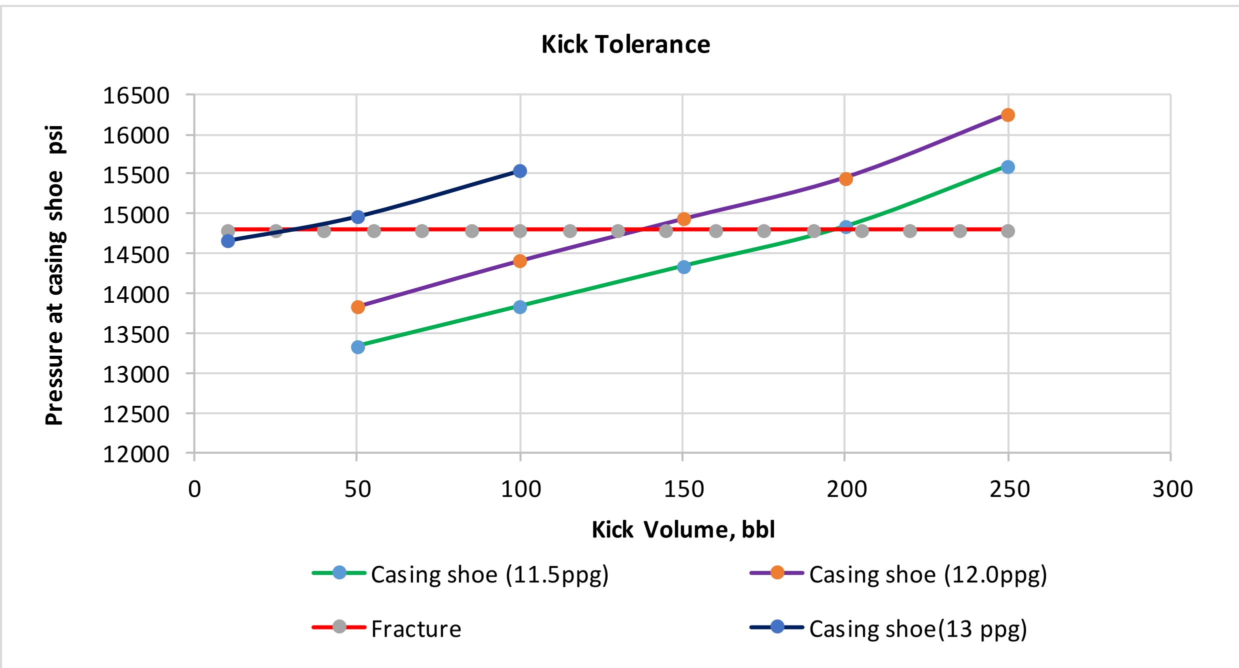


Figure 4.5 Kick tolerance for different mud density as a function of depth and volume.

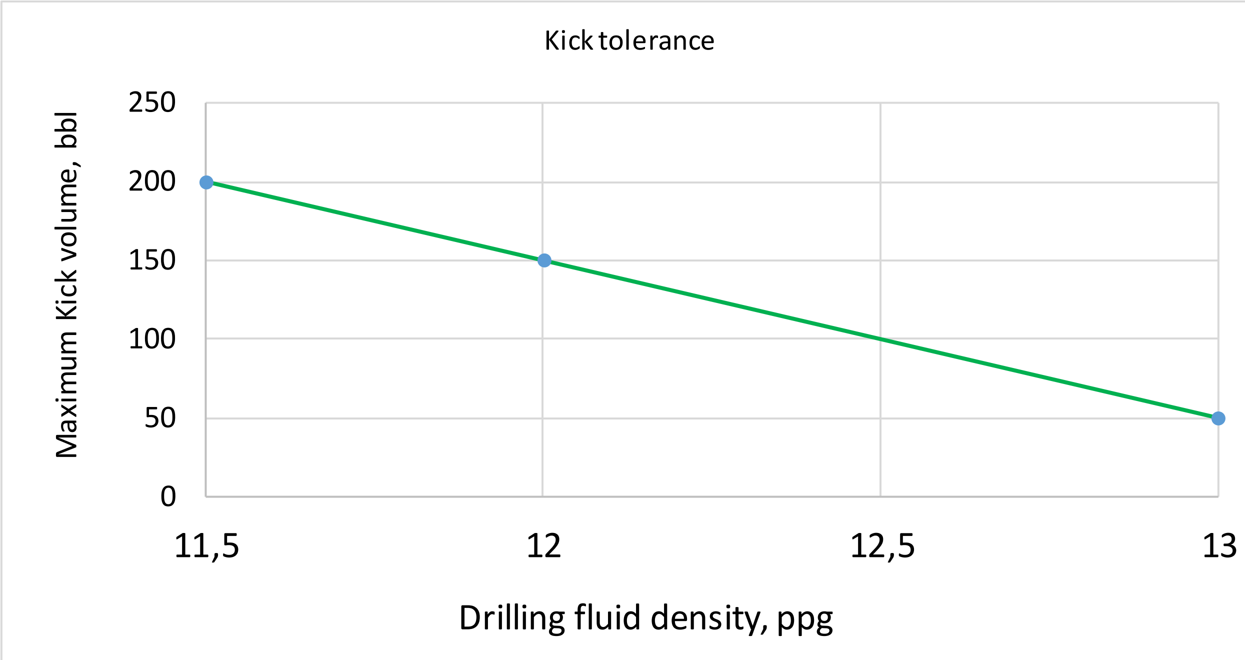


Figure 4.6 Kick Tolerance for different drilling density.

4.3 Managed Pressure Cementing (MPC)

Drilling and cementing in the deepwater environment is very challenging since the operation window is narrow. Manage pressure methods as discussed in section §3.2.4 is one of the methods to handle operation in a narrow window. This section simulates the cementing operating with conventional and manage pressure-cementing technique.

4.3.1 Simulation arrangement

Design analysis for this simulation is done for an open hole section from 20 000 – 30 000 ft. The well depth is 30 000 ft. from *Mean Sea Level* (MSL). The casing shoe is set from 5 000 – 2 0000 ft. with a mud-line of 5500 ft. Figure 4.7 illustrates the well initially filled with drilling fluid (left) and part of the mud circulated out as cement/spacer is filled the annular spacing (Right). Simulation rheology parameters are given in Table 4.6 .The operational window in the operated well is assumed to be between 13.8 – 14.8 sg. The analysis deals with a conventional and MPC. The back pressure was designed to be constant at 519 psi. ECD circulation analysis was performed at different flow rates from 250 to 1500 for all cases. The results are shown in figure 4.8 and 4.9

Table 4.6 Simulation set up

RPM	Spacer	Mud	Cement
	Dial Reading	Dial Reading	Dial Reading
600	-	92	-
300	59	58	153
200	49	46	122
100	37	32	83
60	31		66
30	26		47
6	19	10	19
3	18	8	13
PV, cP	40.65	41.49	91.12
Yield point (lbf/100sqft)	21.93	13.94	11.50
Density, sg	13.00	13.00	14.00

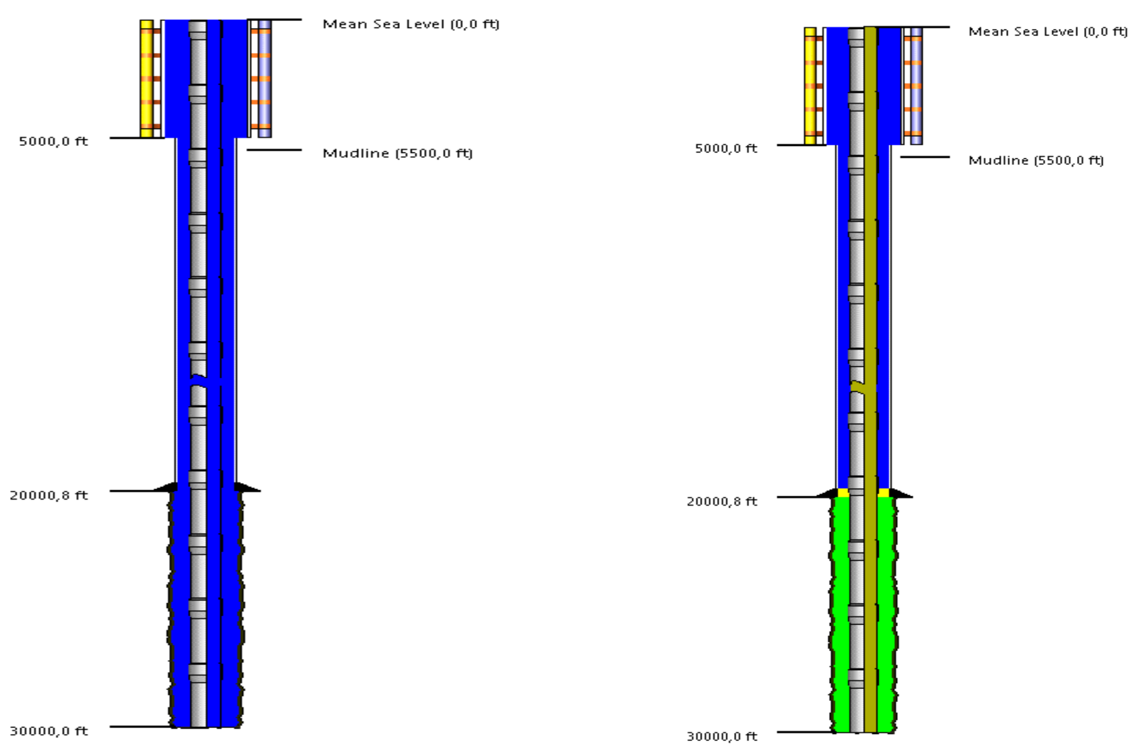


Figure 4.7 Well schematic for the well with and without circulation mud.

4.3.2 Result

The first cementing simulation analysis was performed with a conventional method. The result shows that the well pressure is being outside of the safe operational window (see figure 4.7). That will be problematic because in open hole section from 20 000 ft. where the last casing shoe is set down in formation zone. Equivalent Circulating density is lower than pore pressure for different flow rate between 250 -1500 l/min, which will be troublesome when it is in the reservoir section to cement casing line and will cause kick effect and well collapse as well. By using a higher density and viscosity, and if the resulting well pressure exceeds fracture gradient could, severe to total losses could occur even at the lowest rate possible.

The problem with the conventional method has been solved by applying manage pressure cementing method. As shown in Figure 4.8, the curve lies within the safe window formation by applying additional back pressure of 519. Below the sea floor, which is up to the 6000ft, the well pressure shows exceeding the fracture pressure. However, this is not a problem since the well is already cased up to 20 000ft and casing can handle the shown higher pressure. This simulation result illustrates the application of manage pressure cementing for the deep and Ultra deepwater environment.

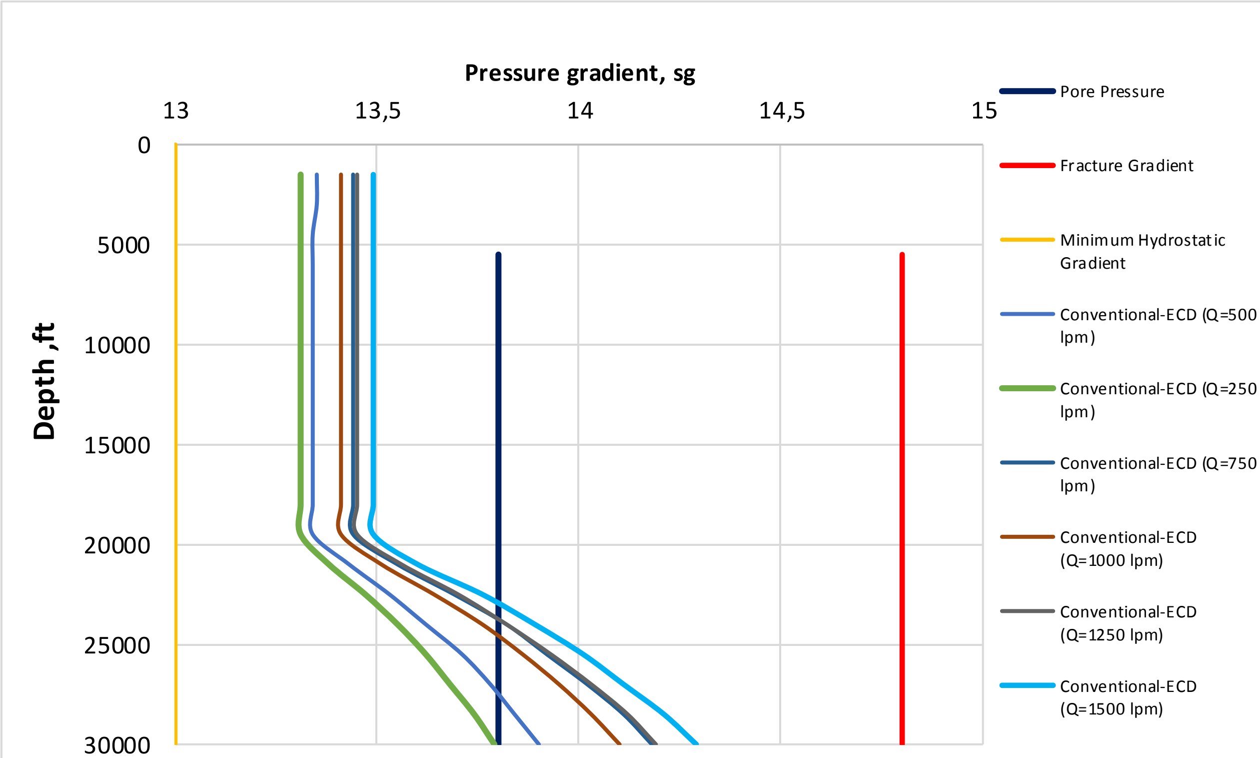


Figure 4.8 Conventional cementing operation, outside the operational window.

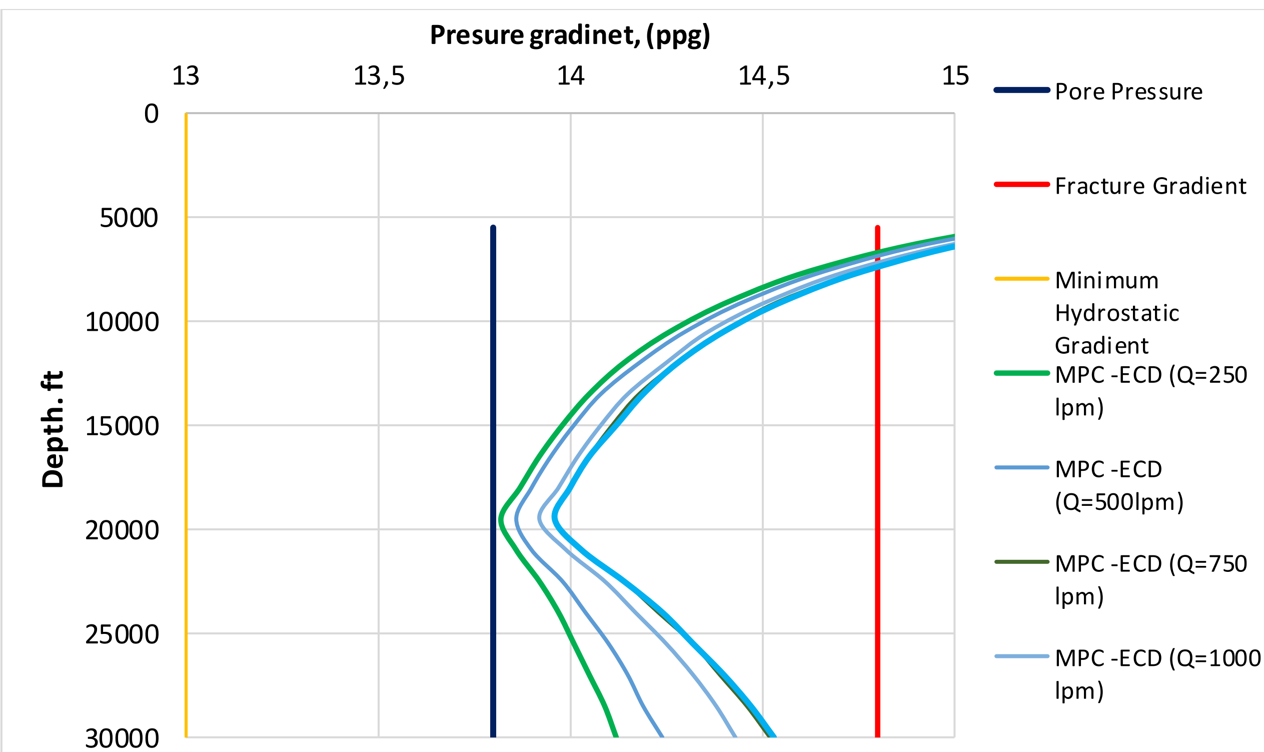


Figure 4.9 MPC within operational window.

4.4 HPHT Well Effect on Drilling Fluid

Kårstad and Aadnøy's model reviewed in section § 2.2.4 has been implemented in Excel® to simulate the effect of Temperature in respect to viscosity and density of drilling fluid. These two parameters are very important for the prediction of hole cleaning and hydraulics of fluid. In addition, the resulting density effect on the buoyancy factor is also simulated.

4.4.1 Simulation arrangement

During simulation, drilling fluid has been circulated at the rate of 0,025m^3/s for 1 hour through 10 000m well. The surface Temperature was 25℃. The thermos-physics parameters of the drilling fluid and the formation along with the size are given in Table 4.7

Table 4.7 Thermophysics parameters of drilling fluid.

Circulation time	t, hour	1
Density of drilling fluid	ρ, m	1700
Flow rate	Q, circulate	0,025
Surface injection Temperature	T_{inj}	29
Specific heat capacity of drilling fluid	c_{fl}	3930
Specific heat capacity of drilling formation	cf	880
Heat conductivity of drilling formation	k_f	2,3
Heat conductivity of drilling fluid	K_{fl}	2,25
Density of formation	ρ_f	2640
Diameter of drill pipe	r_d	0,127
Diameter of casing	r_c	0,2159
Geothermal gradient	g_G	0,013
Total drilling Depth	Depth	10,000

4.4.2 Result

Figure 4.10 displays the simulated drilling fluid Temperature in tube and annulus, along with the formation Temperature as a function of depth. These Temperatures modify the drilling fluid rheology and density properties. As the cold drilling fluid flows through the pipe, the Temperature will increase due to the heat transfer from the formation to the well. The annulus temperature profile is higher than the pipe, which is due to the closed position to the formation temperature. As the circulation time reduced to zero, under static condition by the thermodynamic principle, the Temperature profiles will be the same as the formation temperature. Hence temperature has increased from 22 °Cto 155°C.

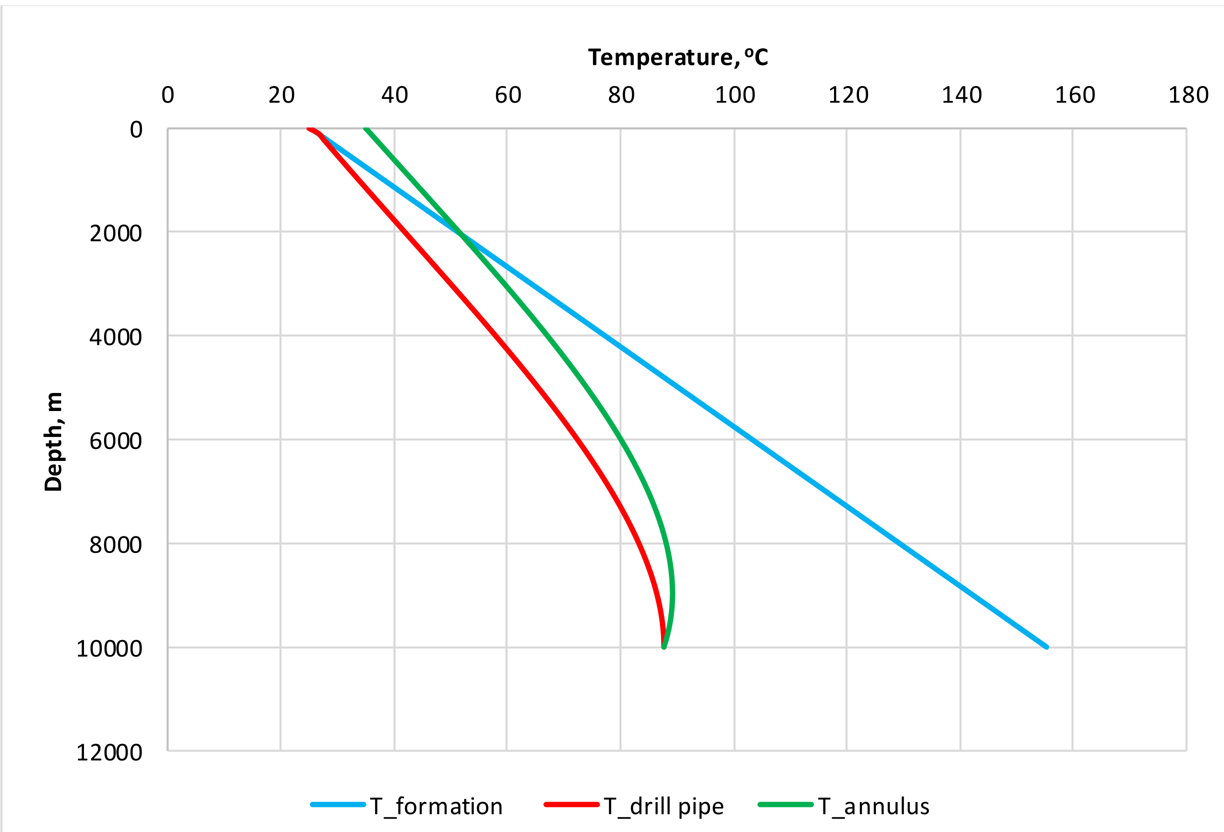


Figure 4.10 Drilling fluid and formation temperature profiles.

Effect of Temperature on Annular and Tube Density of Drilling Fluid

Figure 4.11 shows the drill density in the drill pipe and annulus as a function of depth. With the rise in Temperature, the density decreases along the well, both in annulus and in the pipe. Naturally, this type of decrease in density may lead to kick, and collapse.

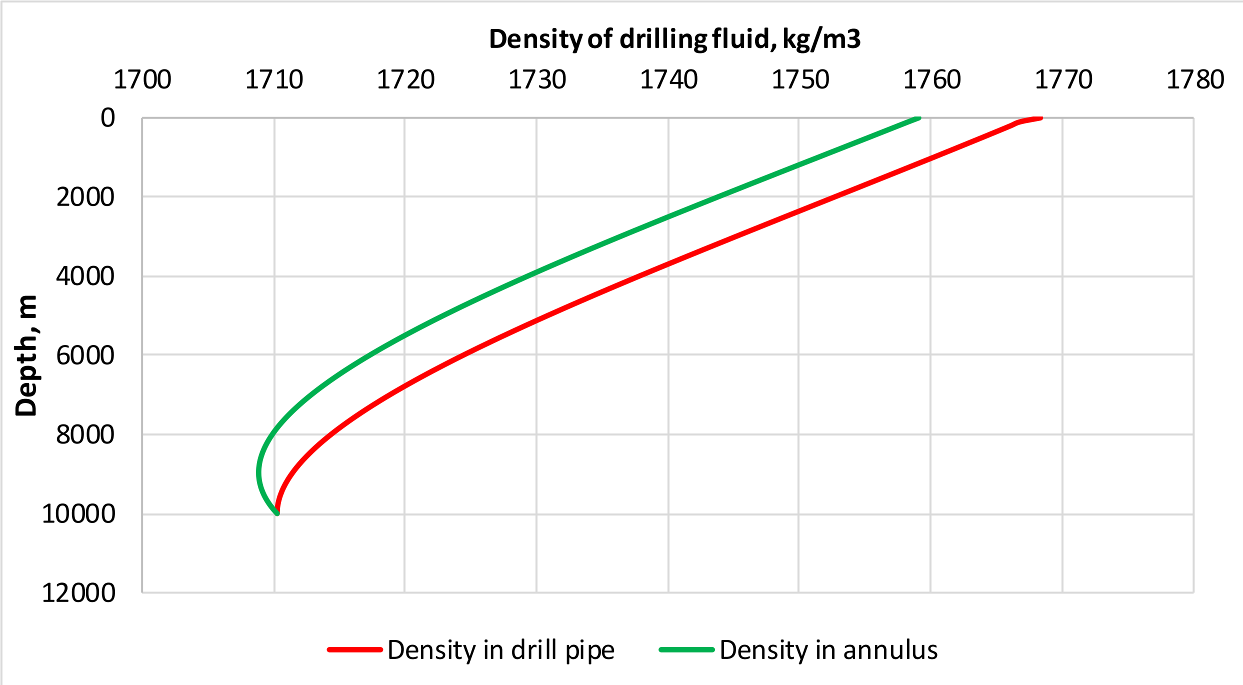


Figure 4.11 Drilling density affected by well temperature

Effect of Temperature on the Viscosity of Drilling Fluid

Temperature and pressure influence the rheology properties of drilling fluid. To evaluate the effect of temperature profiles shown in figure 4.10 the empirical viscosity model reviewed in section §2.2.5 has been used. Figure 4.12 shows the simulated viscosity profiles at a different pressure in drill pipe as a function of depth. Assuming a surface viscosity to be constant at 0.114 cp. As shown, the viscosity will be affected significantly by temperature and pressure. Visocity of mud decreases as a rise in Temperature and increases as pressure increases.

Effect of Temperature on Buoyancy Factor

Buoyancy factor is an important parameter for torque and drag load prediction. It is a function of the density of drilling fluid, and given as Eq. 8 in section § 2.2.3.The effect of temperature on buoyancy factor has been simulated and displayed in figure 4.11. As temperature increases the density of the drilling fluid decreases as illustrated in figure 4.10. This as a result leads to increases in buoyancy factor as shown in figure 4.13. The figure displays the buoyancy factor computed from a constant density and the temperature dependent density profiles. This means that computing the drag force without considering temperature and effect will end up with the wrong prediction.

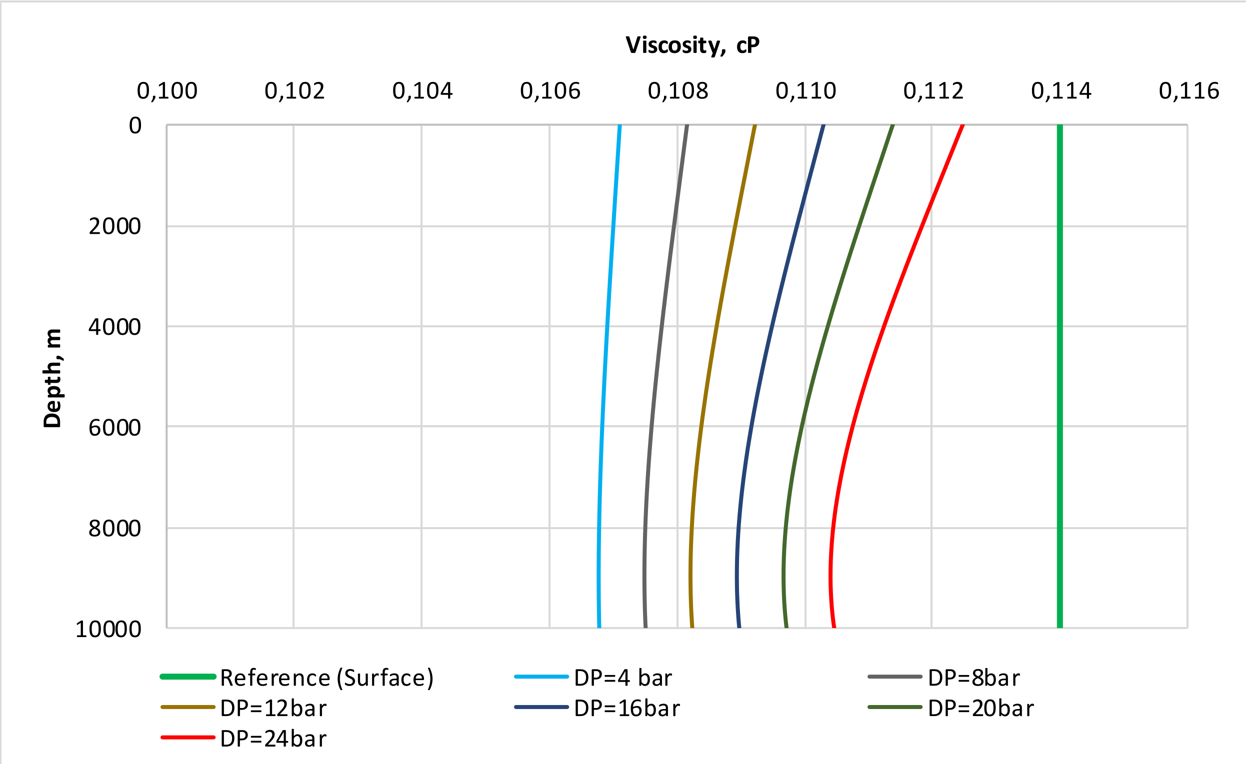


Figure 4.12 Viscosity profile

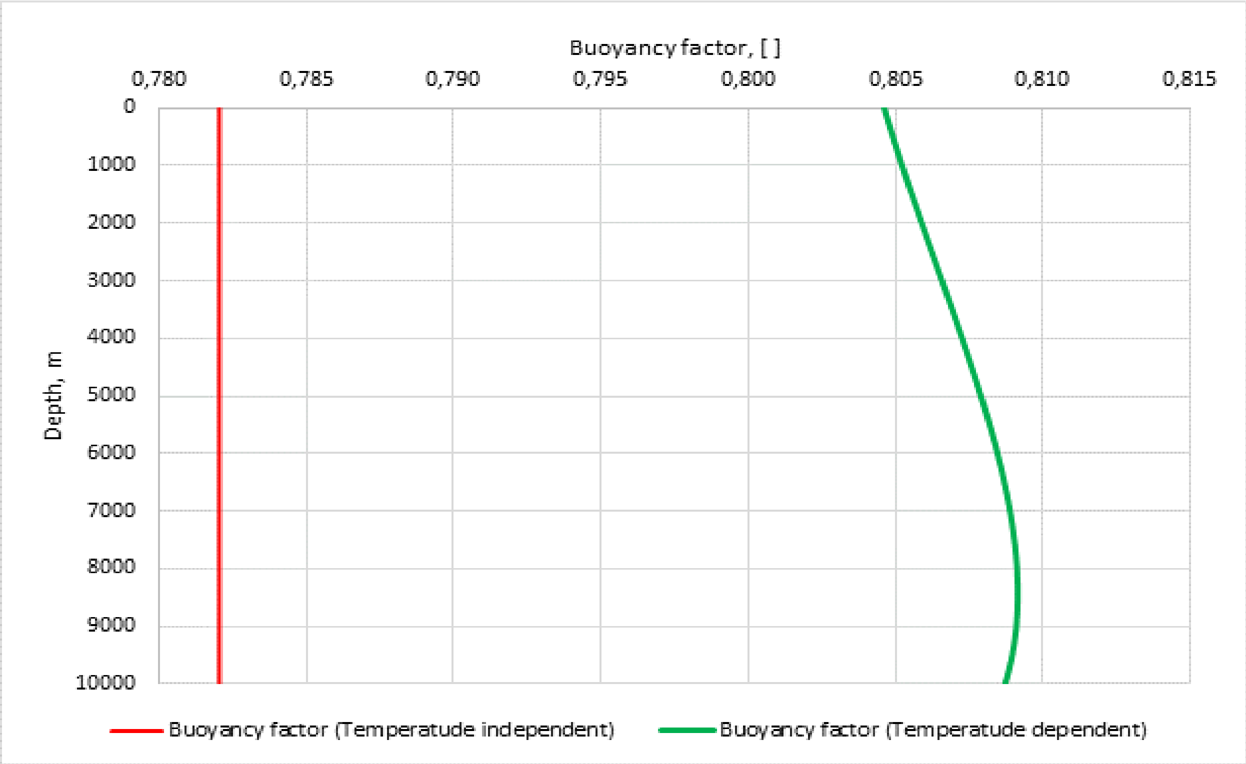


Figure 4.13 Buoyancy factor

5. Results Summary and Discussion

In this thesis, deepwater operation challenges during the lifecycle of the well have been identified along with the technological solutions to handle the problems. These are described in detail based on field case studies presented in chapter 3. In addition, the effect of the challenging environments are simulated and the solution is discussed. This chapter will briefly present the summary and discussion of the results obtained from the operational challenges and solution as well as simulation based studies.

5.1 The life cycle challenges and solution

5.1.1 Exploration Phase

For proper well placement; interpretation formation structure; stratigraphic faults and folds; identification of reliable potential hydrocarbon reservoir; the qualities of seismic data; and imaging technique are very important factors to be considered in the life cycle challenges of exploration. In deepwater drilling, potential hydrocarbon are located at pre-salt and post-salt formation. The conventional methods that was previously applied display poor imaging of these type of region. Among the newer versions of seismic imaging technologies, the *Reverse Time Migration* (RTM) technique provides break through results. Before RTM, simpler conventional methods of exploration were combined together (such as Kirchhoff *depth migration* combined with *wave equation migration* methods) to achieve a better structure imaging. These conventional combined methods did not produce excellent quality imaging results, thus there was a need for more accurate technique where RTM technique was developed. The RTM which is a two-way wave equation migration algorithm provides more accurate imaging. It produces a better imaging, which handles salt formations in deeper water exploration. Using RTM throughout the imaging cycle has proven to reduce uncertainties of seismic imaging to some extent. This technique should be utilized during the whole seismic process regardless of cost or time.

5.1.2 Drilling Phase

5.1.2.1 Drilling Rig

In the recent years, deepwater drilling operations has become more advanced with respect to operational activities and challenges, but economically it is more costly. As water depth increases, the operational challenges are also increasing. However, the industry is developing new generations of drilling rig (TLP, SPAR, FPSO, and SEMI) along with accessories that suits the respected drilling water depth. All types of floating production units described in this thesis represent a feasible solutions for the given conditions. Overall, the main types of vessels will be chosen based on criterion for drilling usable wells at the lowest cost possible. For smaller oil field developments, a stand-alone FPSO will be the optimal choice. For larger development purpose, module platform such as the new generation of semi submersibles with their capability and capacity to operate in even more harsh deepwater environment.

Since deepwater excavation has proven to be an even more challenging task especially with respect to stability for drilling purposes then definitely more attention should be given to work-overs and field development for existing platforms. These particular challenges required more creative design engineering.

To deal with stability challenges, the dynamic positioning (DP) concept is employ to maintain the chosen positioned area by applying active thrusters. It can be used along with mooring or anchoring procedure in order to provide a more robust position while conserving energy. DP vessels can maintain safe and reliable position accuracy thus it is used by the Oil and Gas industry on a worldwide basis. Another advantage of DP its ability for fast relocations to other location area. However, DP has also performance limitation and disadvantages. Thus, more research and development is required to develop an improved drilling rig that handle the challenging issues associated with the rigs and with respect to the environments as well.

5.1.2.2 Riser

Risers are exposed to harsh sea environmental loading such as current, sea wave, and VIV. During drilling and top tensioner, motion compensator handle the dynamic motion of riser. If the loadings are not managed properly, then it may cause dysfunction on riser such as bucking, wellhead fatigues, etc. In addition to sea condition, the conventional steel riser has significant limitation in respect to weight, corrosion ability in salt formation, and length. Therefore, the current design techniques are using Aluminum and Titanium as an alternative material in the design process for steel riser, since they can handle corrosive environment better, less weight, and have good fatigue properties.

In general, before the installation of risers, it is important to have good meteorological data and knowledge of the area in question (worst-case scenario) as well as performing riser simulation studies based on the operational case scenario. It is also important to make sure that the simulation results are in compliance with standards and regulations such as the ISO 13624 [66] and API RP 16Q [67]requirements. *OrcaFlex*™ is popular software package used for dynamic analysis of riser system.

5.1.3 Production phase

During the production lifetime, Temperature and pressure changes in the reservoir and in the well. This occurs during shut-in, production, gas lift and other work over procedures such as bull heading and stimulation. Depending on thermodynamic state, petroleum chemistry problems occurs as solid deposits in flow lines (hydrate, wax, asphalting, and scale), and material integrity related problems due to corrosion. These flow assurance problems increase non-productive time and increase operational costs. It is therefore important to manage flow assurance issues. This is done by designing strategies and principles for a safe and economical flow of hydrocarbons [68].

Figure 5.1 illustrates a typical flow-assurance design process. Flow assurance encompasses different engineering disciplines. As illustrated in the figure 5.1, the flow assurance strategy begins with real-time downhole and surface measurements (Temperature, pressure and production fluids analysis). Prediction of solid deposition/precipitation with simulation tools and taking an appropriate measures to prevent/mitigate the problems. This work process requires continuous monitoring and design flow assurance strategy during the lifetime of a production period. It is important to note that the current technologies to manage flow assurance issues have limitations. Due to the challenging deepwater environmental conditions, more research and development is required with the objective of improving flow assurance in the upstream and downstream petroleum industries.

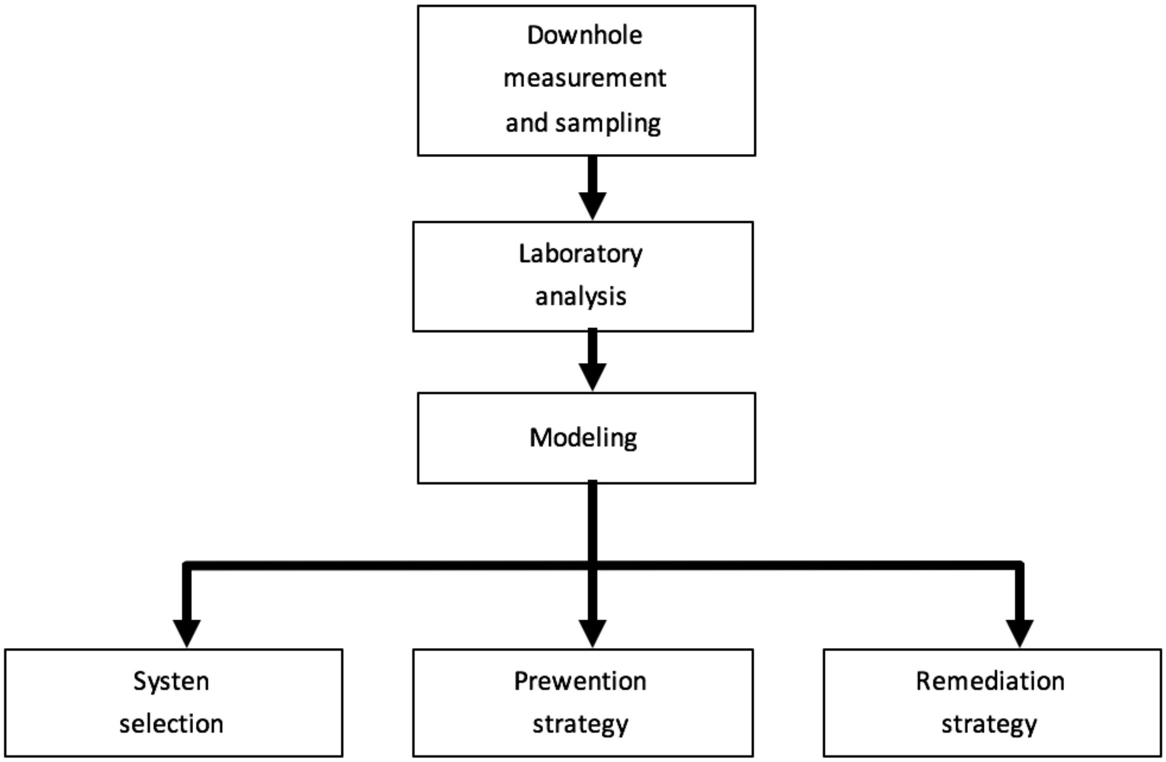


Figure 0.1 Illustration of flow assurance strategy flow-chart [69].

5.1.4 Plug and Abandonment (P&A)

P&A is an operation procedure that takes place at the final stage of the life cycle of an Oil and Gas production field, but if well leaks or its production is not profitable then the fate of the well is to be plugged and then abandoned it. This operation involves spending money without gaining any profit. In deepwater environment, despite the cost. Semi-submersibles are used for P&A operations rather than RLWI. Due to the fact that these type of ships can only operate in depth reaching around 1000 m. Under P&A, removal of production casing strings requires multiple trips that leads to a longer non-production times and subsequently leads to a high rig rate. The new development assembly made by Schlumberger will reduce trip time while removing production casing, which lead to reducing none productive time and lower rig rate. Another cost effective P&A alternative is to divide the operation into the semi-submersibles and the RLWI. The wire line intervention are conducted by operations such as pulling of the casing and tubing on semi submersibles. In this way the workload is shared and the usage of semi-submersibles are reduced leading to savings in cost of operations and rig rate. The future expectation is RLWI service for deepwater wells that reaches to 3000m depth.

In addition, field case studies have shown that the single run P & A method (i.e. Perforate Wash and Cementing (PWC)) reduces the operational time significantly. One field case study from NCS also shows that tubing left in the well reduces the operation time by an average of about 12.8% per well. In the future, more efficient and cost effect P&A technologies would appear on the market. Currently several P & A technologies are under research and developments such as milling technologies (plasma bit milling, reverse/upward milling) and new expandable cement technologies for long-term integrity.

5.1.5 Corrosion

Corrosion is one of the major concern in Oil and Gas production and occurs at all stages of a well life cycle. Corrosion can affect all components starting from reservoir section, and all the way to the platform deck. The consequences of corrosion are economical losses, HSE, and resource protection risks. In the future, most of the drilling wells will be through salt formation and therefore failure due to corrosion on material will increase. Apart from strength, new corrosive resistance materials and protection method should therefore be developed and used during construction phases. To mitigate corrosion related problems, it is important to follow the recommended material selection standards. In addition, it is important to continuously monitor the environmental condition and the material by applying chemical treatment to reduce the corrosion rate. This will prolong the life of the structure.

5.2 Simulation Result

Excel ®and commercial software have been applied to simulate the hydraulics, kick and manage pressure cementing. This section present the summary and discussions of the results.

5.2.1 Annular Pressure Buildup

Annular Pressure Buildup (APB) in deepwater may cause a high risk for casing failure and loss of heat out of the production tubing as a result of increase in Temperature. The numerical examples on the Temperature-induced pressure in B-annulus have shown how the Temperature-dependent pressure increase the APB and the resulting reverse ballooning that lead to elongation of casing. Similarly, the pressure builds up in the tubing due to injection operation results in ballooning effect, which subsequently lead to shorten the production tubing. The thermal expansion (Temperature change) will cause major change in the length of the tubing resulting in compressive force. The case study has shown that APB is a serious challenge facing offshore production facilities and leads to a series of inter-connecting problems that can lead to non-productive times and increase in maintenance and corrective measures.

Several solutions such as the (VIT) and *Insulate Packer Fluid* (IPF) are currently available in the market used to control heat loss from tubing. These solutions has their own application limitations and shortcomings. The future application of nanotechnology may come up with an improved solution to combat this problem. For this, a more dedicated research is required.

5.2.2 Managed Pressure Drilling and Cementing

Based on the simulation result, it is possible to manage the well pressure during cementing operations, which is called Managed Pressure Cementing. It provides a controlled backpressure and allows for precise predicting annular pressure when displacing cement. The main purpose of this technique is to keep the *Equivalent Circulation Density* (ECD) within a narrow window (i.e. between pore pressure and fracture) during drilling and cementing process while maintaining the wellbore stability.

Conventional method of controlling the well pressure is by hydrostatic pressure and annular friction loss. The Simulation result illustrates in section §4.3, cementing with the conventional method that shows the pressure profiles are outside the operational window. In order to solve the challenges of conventional cementing method, the new technology (MPC) was employed, which reduces the risk for operational failure by controlling the annular downhole pressure during cementing/drilling. As shown in the previously discussed section, the MPC simulation was performed by applying a constant back pressure and shifts all pressure profiles within allowable operational safe window.

MPC has been proven to be a technically viable process for cementing critical wellbore section where a conventional cementing approach would be infeasible. Planning is the primary factor for successfully operational planned target without compromising well design and integrity.

5.2.3 Kick Tolerance

The main challenges of the oil and gas industry are how to circulate "kick out" from the well, without fracturing the formation strength at the casing shoe, which is considered to be the weakest point in an open hole section. From the simulation results, it was observed that fluctuation (increase and decrease) in influx and/or lower density of the active mud, directly results in changes in the pressure at the casing shoe. With increasing in influx and/or high density of active mud, the pressure of the casing shoe increase.

The industry, have kick simulations software such as *Landmark/well plan* and *Scan power/drill bench*. During the planning phase for drilling reservoir section, it is important to perform kick simulation based on the right reservoir information and the drilling fluid properties along with the tripping speeds. It is also important to generate several realistic case scenarios so that it can develop kick managing procedure.

5.2.4 High Pressure and High Temperature Drilling Fluid

Drilling fluids are the key factor for drilling operations. Among many others functions, drilling fluids maintain well pressure, transport cutting to surface and cool drill bit. For the appropriate performances, the properties of the drilling fluids such as rheology and density, in addition to chemical properties which are the main factors. During static condition where fluid is not circulating, by the first law of thermodynamics, the temperature in the pipe and in the annulus would be the same as in geothermal temperature profiles. As drilling operation commences, depending up on the circulation time, the heat transfer and the temperature profiles in the annulus and in the pipe are different. Since drilling fluid in annulus is in contact with the formation, the temperature in annulus is relatively higher than the temperature of drilling fluid in the pipe. Due to annular temperature and pressure, the density and viscosity of the drilling fluids change as compared with the surface measurement. These drilling fluid properties affect the hydraulics and hole cleaning efficiencies.

Accurately predicted Temperature and pressure are very important for safe drilling operations. Properly predicted well pressure avoids wellbore instability (i.e. collapse and fracturing) and kick influx. When planning to drill in HPHT formation, it is important to conduct appropriate simulation studies to predict the behaviour of the drilling fluids.

A desirable drilling fluid is required to solve the rheology related problem. In a view of this, the industry has developed a *Flat Rheology* (FR). The test result of the FR drilling fluid indicates that the variation in yield point, and viscosity are not significantly influenced by temperature. Successful performance FR drilling fluids on offshore is well documented in the literature. However, the currently developed FR is not a ultimate solution. Recently, application of nanotechnology in drilling fluid has shown improved drilling fluid properties; the research is at its infancy stage. In the future, more research and development may bring about desired solutions for deep- and ultra deep drilling environments.

4. Conclusion

The thesis has attempted to analyse and answer the issues addressed in section §1.1. For this, the research methodology structured in section §1.3 has been implemented. These are based on field case studies and simulation studies. From the overall evaluation, this chapter presents the major investigation and the main concluding remarks.

6.1 Challenge and solution related major investigations

In chapter 4, a comprehensive study based on field case has been discussed. For the presented challenges, the current technology solutions to handle the problems are also presented. However, still more research and advanced technological development is required. The industry is working on this. Based on the proven applied technologies, the following Tables presents the description and the challenges along with the solution of the lifecycle of deepwater petroleum operation.

Exploration Phase

Description	Challenge	Solutions	Benefits	Application area	Reference
Exploration in salt formation	• Imaging complexity • Kick Off • WEM • Beam Migration	• Reverse Time Migration	• Proper Imaging	Salt formation in Brazil and GOM	[14], [16]

Drilling Phase

Description	Challenge	Solutions	Benefits	Application area	Reference
TLP and SPAR	• Limited deck size • Water depth limit and payload limit • Expensive and required complex offshore installation	• $5^{th}, 6^{th}, and\ 7^{th}$ generation of Semi - submersibles • FPSO • Dynamics positioning system (DP)	• More deck size • Better stability • Increase payload	Ultra-deepwater	*[3]*, *[18]*, *[23]*, *[24]*

Description	Challenge	Solutions	Benefits	Application area	Reference
Environment	• Sea current, • VIV • Wave velocities	• Buoyancy module on TTR • Flexible riser SCR	• Reduce sea conditions effect on riser • Keeping riser tensioned in place • Absorb current and wave effect	GOM and Brazil	[26], [29], [30], [31], [70]
Steel riser	• Heavy weight • Corrosion • Fatigue failure	• Aluminum(Al) • Titanium (Ti)	• Leigh weight • Corrosion resistance • High strength	GOM and Brazil	
Titanium riser	• Wear at flex joint	• Rubber lining 0.25-0.5 in.	• Reduce Flex Joint Wear at casing	Heidrun field	
Drilling fluid	• Change rheological properties	• Flat rheology	• Constant fluid properties • Reduce NPT	GOM, Offshore Sabah	[34], [71]
Pressure control and ECD management	• Kick and loss of circulation	• MPD and MPC	• Reduce NPT • ECD control • Early kick detection	GOM, Brazil West Africa	[35], [36] [38]
Casing point	• High number of casing point	• DGD	• Reduce required number of casing	GOM, Brazil and West Africa	[72]
Heat expansion	• Annular pressure build-up	• VIT • N-SOLATE packer fluid	• Reduce APB effect • Reduce NPT • Cost save	GOM and Offshore Louisiana	[6], [41], [73]
Drilling though salt formation	• Roller cone and PDC drill bit	• Kymera drill bit • Riser less drilling using super saturated brine	• High ROP • Reduce NPT	Santos Basin	[45], [46], [47]
	• Cement carbonation due to CO_2 and H_2S • Hole elongation • poor cement job	• Riser less drilling with super saturated brine	• Reduce cement carbonation • Reduce NPT •	Santos basin in Brazil	[44]

Production Phase

Description	Challenge	Solutions	Benefits	Application area	Reference
Flow assurance	Gas Hydrate	• Gas hydrate inhibitor • Thermodynamic inhibitor • Cold Flow • Water removal	• Reduce gas hydrate • Reduce NPT	Deepwater area	[6], [51], [52], [53]
Flow assurance	Wax	• Cold Flow • Heat application • Fused Chemical reaction • Mechanical removal	• Reduce Wax • Reduce NPT	Deepwater area	[6], [55]

Plug and Abandonment

Description	Challenge	Solutions	Benefits	Application area	Reference
P&A	• Expensive rig • Tubing • Corrosion • Multiple trip removing long tubing • Section milling •	• Using RLWI • Tubing left in the hole • PWC • Hydraulic cutter • Plasma bit milling • Reverse section milling	• Save cost and reduce NPT • Reduce leakage due to cement	Deepwater area	[56], [57], [58], [59], [61] [74],

Corrosion

Description	Challenge	Solutions	Benefits	Application area	Reference
Corrosion	• HSE issue • Damage to material • Reduce well integrity • Attack equipment made by metal • NPT	• ThermaLock™ • Salt Shield℠ • Organic and Metallic Protective method • Chemical coating • Corrosion resistance alloy	• Reduce casing collapse and drilling riser • Reduce NPT • Better well integrity • Less HSE problem	• Japan • Indonesia • GOM	[6], [48] , [49], [64]

6.2 Concluding remarks

Based on literature study and design simulation analysis, this work finally concludes that:

- Good and reliable seismic imaging technology is a key for proper placement and drilling through salt formation. RTM is a suitable technique combined with 3D data processing.
- Selection of deepwater drilling rig depends on several factor such as; economy, water depth, field size, drilling work over capacity, production capacity and total top side weight as well as the field location. The new generation of semi-submersible is the best fitting platform for Ultra-deepwater.
- Steel riser with buoyancy module may reduce tension effects. Since the deepwater environment is harsh and highly corrosive, alternative risers such as Titanium and Aluminum are best candidates. These weigh less with good corrosion resistance and fatigue endurance limit. In addition, insulating with rubber at flex joint reduces wear damage.
- Deepwater conditions, such as pressure and Temperature, influence fluid rheological properties; flat rheology application reduces any effect on the fluid.
- Applying MPD and MPC will respectively reduce obstacles regarding kick, cementing well and reduce number of casing points.

- Well control in HPHT shown that one of the most crucial areas for development in well control in a safety is early kick detection. Using a micro flux detector improves kick and loss detection.
- For problematic salt formations, Kymera drill bit used for faster rate of penetration, and super saturated drilling fluid used for drilling in top hole section with riser less drilling.
- Annular pressure build-up can be mitigated using vacuum insulated tubing and insulated packer fluid to reduce heat transfer.
- Hydrate and wax can be controlled by dynamic cold flow, removal techniques using fused chemical reaction, mechanical removal, heat application, wax removing chemical, microbial products. In addition, hydrate inhibitor such as thermodynamic, kinetic inhibitor. Cold flow turned out to be the most effective technology to remove gas hydrate compared with other methods.
- Corrosion deteriorates the life of the well. It is therefore important to give special attention during design phase in order to select the right material. In addition, it is important to continuously treat the system with corrosion inhibition control chemical in order to reduce the corrosion rate.
- Cement placement with tubing left in the hole and PWC during P&A phases will considerably save time and massive cost saving.

There will be more of deepwater drilling causing more plugging and abandonment of wells. Advanced technology should be applied and studied to overcome future prospects. At the end, selection of the technology and methods will be dependent on budget, location, environment and the time frame.

There are already several technologies in the industry. New technology has been proven to ease some of the challenges of deepwater drilling, but there is still need for it to be more efficient and maybe cheaper in the long run. Due to the oil crisis and economical, the investment of developing progressive technology might decrease. However, in the future more research should be conducted to handle the deep - and Ultra-deepwater operational challenges.

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